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**1989
Supplement
to the
1986
Northwest Conservation
and Electric Power Plan
Volume I**

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Note: All figures used in both volumes of this supplement are in 1988 dollars unless otherwise specified. Since the Northwest's hydropower system is primarily energy constrained, the term "megawatts" refers to average annual megawatts unless otherwise specified. All references to "energy," "capacity" and "power" refer to electrical energy resources only.

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The Northwest Power Planning Council adopted a 20-year Northwest Power Plan in 1986. The Council designed this plan to provide a stable blueprint for meeting the region's future electricity needs at the lowest possible cost. At the same time, the plan is a flexible document that can be adapted to reflect new information. The Council regularly monitors changing regional and national conditions, including the plan's implementation, to determine whether the basic policy goals it identified are being achieved. This monitoring helps signal when either fine tuning or more fundamental changes are needed.

Regional and international developments in the three years since the plan's basic analysis was completed have changed energy supply and demand conditions. The Northwest's recovery from a recession that occurred earlier in the decade translated into increased demand for power. In particular, higher aluminum prices enabled that industry to recover, thus raising its demand for electricity. This economic upturn coupled with closure of the Hanford Generating Project (a nuclear-fueled power plant in Washington) and sales of firm surplus power outside the region, reduced the Northwest's power surplus.

On the world scene, oil prices—which influence demand for other energy resources and the cost of some electricity generation—collapsed in early 1986, after the power plan had been adopted. In addition, developments and refinements in technologies to conserve or produce power, changes in the availability and costs of several resources, and the completion of studies that provide new information and data have also changed the electricity picture.

Of all of these, the biggest change affecting the plan has been the decline in the region's electricity surplus in the last three years. The regional surplus in 1986 was approximately 2,500 average megawatts. But that had dropped to approxi-

mately 1,400 megawatts in early 1988, and is estimated to decline to between 400 and 800 megawatts by 1990. The 1986 plan anticipated such a decline in its range forecast of future electrical needs and included actions to respond to it.

The surplus for the Bonneville Power Administration's system (which includes power sales to about half the region) was approximately 1,900 average megawatts in 1986. That surplus is expected to decline to approximately 350 megawatts in 1990, assuming full direct service industry loads. (Direct service industries—primarily aluminum smelters—buy power directly from Bonneville.)

Shrinking surpluses mean that the region should be fully implementing the actions that the Council included in the Action Plan in 1986. The Action Plan is the portion of the Northwest Power Plan that describes steps to take now to ensure that the region meets its electric energy needs reliably and at the lowest cost.

Major Conclusions

The changes described above prompted the Council in 1988 to update the technical data base of its 1986 Northwest Power Plan. That process was concluded in March of 1989. This supplement incorporates the most current technical information available. It provides up-to-date information to the region's utilities and to agencies that use the plan in their decision-making, such as state utility commissions and the Federal Energy Regulatory Commission. The revisions have led to three major conclusions:

- The region's electricity surplus is substantially smaller than when the 1986 Power Plan was adopted, and action will be required in the near term to meet the region's needs.
- The 1986 Action Plan contains appropriate activities for the next few years. While most of the Action Plan does not need to be changed, Bonneville and the region's utilities

need to move more aggressively to implement these activities to ensure a reliable energy future. In addition, the schedule for implementing discretionary conservation programs needs to be reviewed.

- There are a number of major issues that must be resolved to refine the list of resources that may be needed for the 1990s. These issues will be addressed over the next two years.

Background

Public involvement in the updating process began in January 1988, when the Council published a staff issue paper called "Plans for a Technical Update to the 1986 Power Plan." This was followed by several staff issue papers calling for public comment on key planning areas including economic, demographic and fuel price assumptions; demand forecasts; and analyses of the cost and availability of conservation and generating resources.

The update process had several goals:

1. To ensure that the plan continues to be comprehensive and reliable enough to meet the region's electric energy needs at the lowest possible cost.
2. To work with Bonneville to avoid duplication in developing the forecast, resource supply curves (how much energy is available at different prices) and the decision model (the computer model used to analyze the lowest-cost mix of resources based on a range of future needs).
3. To identify major issues and/or new information that require attention from the Council and the region.
4. To review the Action Plan for subsequent revision, as appropriate.

After extensive public comment on the update issue papers, the Council's staff published a draft update, which included all areas covered in the issue papers. The

consensus of commentors on that draft was that it was proper for the Council to update its demand forecast and the technical underpinnings of the power plan. But many parties, especially those representing utilities, argued that, while major policy issues should be identified at this point, decisions on certain issues should be deferred to allow more time for regional discussion. In particular, several utility representatives said that the draft resource portfolio (the list and schedule of resources) in the staff update, which was based on new cost estimates, made too many changes, in too short a time.

As a result of the comment on the update, the Council has scaled back the more controversial resource portfolio figures in this supplement to their values in the 1986 Power Plan. These include cost and performance data for cogeneration, transmission- and distribution-system efficiency improvements, conservation voltage regulation, and strategies to back up nonfirm power (making better use of the hydropower system), as well as figures on the availability of coal. The Council's assessment of these resources is included in Chapter 4 of this supplement.

The commenting parties agreed that the region should turn to an in-depth discussion of these resources and other major issues over a longer time span—perhaps as long as two years. The priorities identified will be the subject of future issue papers and public involvement opportunities, which could lead to a new power plan with a revised Action Plan.

The Council will be reviewing all conservation and generating resources and updating information on their costs, availability, reliability and acceptability to the region. The Council also expects to address critical factors that affect resources, such as environmental impacts, delivery systems, and barriers to resource development. The status of agreements and treaties governing resources will also be examined.

Integral to this review will be an overall consideration of the changing utility environment, with emphasis on the effects of the movement toward deregulation and least-cost planning. For a more comprehensive overview of the issues identified as meriting discussion in the near future, readers are referred to the power planning division's current work plan. (Request document 89-4 from the Council's public involvement division.)

The update process achieved many of the Council's initial goals. Working with a broadly representative advisory group, the Council has developed more up-to-date information about electricity needs and resource costs. The Council and Bonneville have also worked jointly to develop a forecast and resource supply curves.

Perhaps the most positive result of the update process has been the fact that senior utility executives have expressed a commitment to get more involved in Council planning and to improve the link between the plan and utility actions.

There are obvious links. While the regional plan does not tell individual utilities when they need resources, it does provide uniform information about resource costs and availability. It also provides a process for determining how to deal with uncertain future energy needs, what electrical load growth to plan for, what resource lead times planners can anticipate, what situations trigger the resource acquisition process, and what resource characteristics most benefit the power system. The Northwest Power Plan provides a yardstick for individual utility planners against which to measure their own actions.

If one overriding concern remained as a result of the update process, it was that there appears to be a lack of understanding about the relationship of the power plan's resource portfolio—its list and schedule of new resources—to the Action Plan. Public comment during the

update process showed strong concern over changes recommended in the resource portfolio. This was despite the fact that no changes were made in the Action Plan, which directly influences the actual dollar expenditures for new resources.

The resource portfolio is designed to reflect the best estimates at this particular time of the lowest-cost mix of resources to meet an uncertain energy future. In short, it is a "snapshot" that indicates what resources the region could rely on if a decision had to be made now. The portfolio establishes a benchmark against which other resources can be compared in terms of costs and characteristics. It also tells the region when resource decisions that involve significant expenditures may be needed.

The Council assumes that if better, less-costly resources become available, they should be used in place of the resources presently in the portfolio. The plan particularly encourages the development of low-cost renewable resources so that they will be available before the region needs to consider building new generating plants. Therefore, the costs of some of the resources discussed in the portfolio, such as coal plants, have been used to measure the cost-effectiveness of alternative resources and to establish the timing for resource acquisitions.

This supplement summarizes technical changes to the 1986 Power Plan. Volume II of this supplement contains the complete technical background for these changes. Copies of Volume II can be obtained free of charge by contacting the Council's Public Involvement Division, 851 S.W. Sixth Avenue, Suite 1100, Portland, Oregon 97204. Call toll free in Oregon 1-800-452-2324 or in Idaho, Montana and Washington 1-800-222-3355.

The Legal Effect of this Supplement

This supplement does not include all the information in the 1986 Northwest Power Plan and should be read in conjunction with that document.

The supplement and its technical support in Volume II are considered part of, and an amendment to, the Council's 1986 Northwest Power Plan. Specifically, the supplement affects portions of Chapters 1 through 8 of the 1986 Power Plan. It does not modify or otherwise affect the Action Plan (Chapter 9) of the 1986 Power Plan. In those instances where the information or conclusions contained in the supplement conflict with existing language in the 1986 Power Plan, the language in the supplement supersedes the language in the plan. In all other instances, the supplement is to be considered an addition to the 1986 Power Plan.

The Council recognizes that the information and conclusions contained in the supplement may suggest the need for further revisions to the 1986 plan, including the Action Plan. The Council intends to address those further revisions over the next two years.

The Council's Planning Process

"Least-cost planning," as used by the Council, refers to a process for developing and implementing a resource acquisition strategy that will enable the Northwest to meet its electricity needs reliably and at the lowest cost, taking into account the uncertainty of forecasts, environmental considerations and the compatibility of new resources with the existing power system. The Council begins its planning process with a thorough analysis of the region's demographic trends, economic development and existing energy demands. It then uses these patterns of use and predicted growth to develop ranges of future demand for the next 20 years. The Council evaluates all

alternatives for meeting electric service needs on a consistent basis. Improving the efficiency of electricity use through conservation programs is treated as a resource. Taking into account existing resources, the Council then projects what mix of new resources might need to be acquired across the 20-year planning horizon to meet the region's energy futures at the lowest cost to society, while at the same time reducing risks of overbuilding or underbuilding to an acceptable level. Finally, the Council develops a plan of specific actions that should be taken in the near term to meet the region's long-term energy needs.

The Pacific Northwest has gone through an enormously expensive lesson in underestimating the uncertainty and risks associated with power planning. In the 1970s, the region's utility planners typically produced single-point forecasts, confident that economic growth in the Northwest would continue to increase at one constant and high rate. As recently as 1980, utility forecasters were still predicting brownouts or worse for the region as early as the mid-1980s. To meet this anticipated growth, the region began to plan and construct a total of 10 nuclear plants and 18 coal plants. Based on the region's experience, forecasters figured that if their single-point predictions were too high, growth would quickly cover any potential overbuilding. However, growth rates did not continue as they had in the early 1970s, and utilities were left with large investments in generating plants with no place to sell the power. As a consequence, rates rose dramatically.

Today, only two of the nuclear plants have been completed, two more are on hold in a partially completed stage, and six have been terminated. The capital cost of the terminated and mothballed nuclear plants exceeds \$7 billion. More than a dozen coal plants have been completed, and an additional licensed site capable of supporting 1,000 megawatts of coal-fired capacity has been secured. The costly lesson for the region is that

there are substantial risks involved in trying to match resources to uncertain future energy needs.

The keystone of the Council's planning philosophy, designed to manage those risks, is the express recognition of the uncertainty surrounding virtually every aspect of energy planning. Instead of fixing on a single-point prediction of the region's energy future, the Council's methodology embodies plans to meet a range of possible futures, as described more fully below.

An important reality check in the Council's least-cost planning process is public involvement. The Council forms broadly representative advisory committees to review the forecasts and resource assessments. The details of this analysis are published and circulated, and public comment is taken at the Council's regular meetings as well as in writing. This preliminary analysis encourages organizations and individuals to test the assumptions and methodology used by the Council and improves the quality of the final product.

The Council works with all interested organizations in the region to develop commonly accepted analytic tools. As a result, regional debates can focus on important policy considerations rather than on differences in the computer models used by various organizations. In addition to improving the quality of information and focusing policy debates, the Council's public process helps to ensure that all interested parties share the same set of factual assumptions. This enhances communication and helps build a consensus for actions.

Six Steps for Least-cost Planning

In selecting the resources described in this plan, the Council followed the directions of the Northwest Power Act. The Act requires the Council to produce a plan for developing resources, including conservation measures. The Council

must consider environmental quality, compatibility with the existing regional power system, and impacts on fish and wildlife. The Act also requires the Council to develop model conservation standards, designed to make buildings use electricity efficiently.

In accordance with the Act, the Council selects resources that are cost-effective. The Act defines a "cost-effective" measure or resource as one that is forecast to be reliable and available within the time it is needed at an estimated incremental system cost¹ no greater than that of the least-cost similarly reliable and available alternative. Cost-effectiveness is a function of need, relative cost, reliability and availability. The plan is based on the premise that the region should buy only the resources that it needs; and it should buy the lowest-cost resources, counting all the costs involved on a consistent basis.

The Act requires the Council to give first priority to conservation, second to renewable resources, third to generating resources using waste heat or generating resources of high fuel-conversion efficiency, and last to all other resources. Finally, the Act provides a 10-percent advantage in calculating the estimated incremental system costs for conservation measures.

Step One: Initial Determination of Resource Needs

The planning process starts with the recognition that the future is uncertain, and it is not possible to forecast electrical energy needs with precision. The Council has chosen to deal with this uncertainty by defining plausible boundaries for the region's energy growth. To do this, the Council developed a range of high, medium-high, medium, medium-low, and low electrical load growth scenarios over the next 20 years. The region's actual de-

mand for electricity is most likely to be between the medium-high and medium-low boundaries.

The Council began with an extensive process to determine the range of future electrical energy growth for the major end uses of electricity, based on economic and demographic projections and the price of electricity. Estimated future prices of alternative fuels are also key factors in forecasting electricity use.

The Council has selected a high upper bound to ensure that the region has the ability to supply electricity for any potential need. It is also important to note that, while the Council develops an inventory of actions to meet this upper bound, the region will not build all these resources unless high growth actually occurs. In addition, lower-cost resources than those in the plan may be available and reliable at the time of acquisition, in which case, they can be substituted for those listed.

The range forecast represents the prudent span of future energy use patterns and defines the magnitude and schedule of actions needed to meet that range of use. This demand forecasting process is described in more detail in Chapter 2 of this supplement and Chapters 1 and 2 of Volume II.

The Council developed its best estimate of the existing resource base, including any known additions or reductions (e.g., resources nearing completion or retirement, and power contracts that expire or begin within the next 20 years). Existing resources were then subtracted from the range of future electricity demands to determine the amount of conservation and generating resources that may be needed in the future.

Step Two: Initial Resource Assessment

The Council began this review by examining the availability, reliability and costs of all generating and conservation resources. All direct and administrative costs for conservation and generating resources were analyzed. This approach explicitly recognized that there is no demand for electricity *per se*. Electricity provides services such as heating and lighting. These services can be met by improving the efficiency of electricity use or increasing the supply of electricity by adding new generation. For example, measures that improve the energy efficiency of a building provide the same service (a comfortable place to live or work), and they free up electricity that can be used to provide other services.

Environmental impacts also were assessed, and costs were included for adapting technologies to avoid or reduce to acceptable levels the impacts of each resource on the environment, fish and wildlife. These costs include all measures needed to meet federal and state regulations. The Council also developed a methodology for analyzing other quantifiable environmental costs and benefits.

The products of this analysis are "supply curves" for each resource. These curves estimate how many megawatts of a resource are available across a range of costs. In order to evaluate all resources on a comparable basis, all costs were calculated on a levelized life-cycle basis using 1988 dollars as the reference year.

Resources were divided into "cost-effective" and "promising" categories. Cost-effective resources must use

1./ System cost is defined to be an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, costs for distribution and transmission, waste disposal, end of cycle, fuel, and quantifiable environmental measures. The Council is also required to take into account projected resource operations based on appropriate historical experience with similar measures or resources.

commercially available technology, have predictable and competitive costs and performance, and must use a demonstrated resource base. Development of the resource must not have institutional constraints (legal, financial or regulatory), and the resource must be environmentally acceptable according to current policies, laws, regulations, and the Council's Columbia River Basin Fish and Wildlife Program. Further discussion of environmental criteria is included in Chapter 9, Volume II of the 1986 Power Plan. Promising resources may be considered for future resource portfolios if their availability, reliability or system cost improves. The plan includes research, development and demonstration activities to address promising resources.

The cost and supply of conservation is discussed in Chapter 3 of this supplement and in more detail in Volume II, Chapter 3 of this supplement. Generating resources are addressed in Volume II, Chapter 4 of the supplement. The financial assumptions and cost-effectiveness methodology used by the Council is discussed in Chapter 4 of Volume II of the 1986 Power Plan.

Step Three: Integrated Resource Analysis and Risk Management

The Council then analyzed the lowest-cost combination of all resources that would be needed to meet the entire range of potential energy needs. State-of-the-art computer models were used to simulate how each resource would operate within the existing power system to determine the actual costs the region is likely to incur. This analysis also determined the compatibility of each resource with the existing power system. Alternative resources were evaluated against hundreds of different load scenarios to simulate the uncertainty and volatility of future energy needs. For more information, see Chapter 8 of Volume II of the 1986 Power Plan.

Non-discretionary resources were the first added into the portfolio. These are cost-effective resources whose timing cannot be scheduled or controlled by the power system. For example, the opportunity for incorporating energy saving measures in new residential and commercial buildings will occur when the buildings are built. If the resources are not installed, the opportunity to save the energy will be lost. The power system cannot control the timing of these lost opportunities, but it can take action to secure all cost-effective electrical energy savings at the time of construction. Discretionary resources can be scheduled by the power system to produce energy and can be acquired when they are needed. The portfolio and cost-effectiveness analysis are discussed in Chapter 5 of this supplement.

Several resource characteristics were identified as particularly important in providing the flexibility to adapt to uncertainties that could increase the region's electricity rates. As the Council looked for the lowest-cost resources, it analyzed how a resource interacts with the existing power system and all the quantifiable costs that must be borne by society over the entire lifetime of a project, including construction, operation, transmission, distribution, decommissioning and environmental costs. The Council recognized that resources with short lead times, small plant sizes and low capital costs can reduce risk. Smaller resources that can be constructed and brought into operation quickly give the region a much better chance of matching supply to energy needs. Resources that are correlated to load growth such as conservation from building and appliance efficiency standards, also help reduce uncertainty by supplying increased energy savings as the population and the economy grow.

Step Four: Policy Considerations

In re-evaluating the cost-effectiveness of resources, other attributes were considered to determine the appropriateness of each new resource. As explained above, some resources such as conservation help reduce the uncertainty of future load growth. Others are particularly flexible, because they have short lead times to construction and are smaller, so they also assist the region in adapting to changing circumstances. In addition, the Council reviewed environmental concerns, and weighed the value of fuel diversity and the risks of fuel cost escalations in its resource considerations. Finally, the Council decided whether enough valid cost and performance information is available on which to make an informed judgment.

The Council has relied on its demand forecasting, system analysis and decision models as aids to decision-making. It is important to emphasize, however, that the models are used to analyze decision alternatives, and not to make decisions.

Step Five: Final Resource Portfolio

Through this integrated resource analysis, the Council identified a portfolio of all the resources that may be needed to meet the range of future loads and ranked them so that the most cost-effective overall will be developed first. The portfolio provides a schedule, as well as a sequence, for making resource decisions. The costs associated with the portfolio are reinserted into the forecasting system to develop the final forecasts of electricity needs, which are used to fine tune the final amount of resources that are needed.

The Council's planning strategy continues to be based on what has come to be known as a "societal perspective." The objective is to minimize the total present-value system costs to the "society" served, whether those costs are borne by utilities, and thus reflected in electric rates, or by individuals, businesses, and governments acting in their own self interest. This approach may not result in the lowest electricity rates in the short term, but, rather, minimizes the total long-term cost of providing electricity services for all ratepayers in the region.

Step Six: Action Plan

Based on the final portfolio of resources to meet potential energy needs over the next 20 years, the Council determined which specific actions are required in the near term (within five years) to prepare the region to meet its long-term needs. These actions are described in Chapter 9 of the 1986 Power Plan. The Council also called on Bonneville to develop a process for acquiring resources that are cost-competitive with the resources included in the plan.

The Action Plan specifies a number of steps to be taken by Bonneville in the

near term. It also includes recommendations for investor-owned utilities and for the state utility regulatory commissions. Key activities in the 1986 Action Plan include the following:

- Acquisition of all lost-opportunity resources; that is, resources whose cost-effectiveness will be lost to the region if they are not acquired now (e.g., energy efficiency in new construction).
- Development of the capability (testing and demonstration of feasibility) to deliver conservation programs in all sectors.
- Development of a process to acquire resources and resource options. The process should encourage evaluation of all cost-effective resources regardless of whether or not they are in the Council's plan.
- Confirmation of promising renewable resources, such as geothermal, wind and solar, as well as resources such as transmission and distribution efficiencies and voltage regulation.

- Development of strategies to make better use of the existing hydropower system.
- Exploration of sales, purchases and exchanges of power among regions to determine mutually beneficial arrangements.
- Development of mechanisms to transfer conservation savings and other low-cost resources from utilities that have a surplus to those that have power needs.

Given the declining surplus, full implementation of these elements of the plan is extremely important. Information from the updating process indicates that these Action Plan priorities remain timely and appropriate to address the needs raised by a declining surplus. The region can achieve a least-cost future only if the Action Plan is implemented. The process outlined for reviewing controversial resources will help refine the resources, beyond conservation, that may be needed in the 1990s.

Chapter 2

Future Electricity Needs

The region's need for new resources cannot be determined without forecasting the demand for electricity. Demand forecasts play three important roles in the Council's power planning process. The first is the traditional role; they provide the basis for deciding how much electricity is needed to support a healthy and growing economy. The second role is to explore and define the uncertainty surrounding future electrical resource needs. Finally, conservation, identified as the priority resource in the Act, is directly related to the demand for electricity. Demand forecasts play a dual part in conservation planning: they both determine the conservation potential associated with various levels of demand, and they help calculate how much programs to acquire conservation resources reduce demand.

The growth of the regional economy and changes in its composition are the key factors affecting growth in demand for electricity. Changing prices of fossil fuels and electricity, however, can significantly modify the effects of economic conditions. Electricity prices are estimated based on the amount of power that is needed and the cost of resources needed to generate it. The Council has developed the best available forecasting tools to capture these relationships in considerable detail.

Since future conditions are highly uncertain, the Council puts a high priority on exploring alternative possibilities for future electricity demand. The forecast of demand for electricity consists of a range of five forecasts: a low, medium-low, medium, medium-high and high forecast. The high demand forecast is designed to ensure that power supplies never constrain the regional economy's growth potential. The high forecast portrays a future in which regional economic growth achieves record high levels, rela-

tive to national growth, combined with less competitive prices for alternative fuels. The likelihood that such a rapid regional growth will occur is considered to be small. The Council's forecast range is bounded on the low side by a forecast that is pessimistic about the regional economy roughly in proportion to the optimism of the high case.

Inside the bounds of the low and high forecasts is a smaller, more probable range of demands bounded by the medium-low and medium-high forecasts. The medium-low, medium and medium-high forecasts will carry a greater weight in the planning of resources than will the high and low extremes. Nevertheless, the possibilities posed by the high growth forecast must be addressed by appropriate resource options. Similarly, conditions that are implied by the low demand forecast will be considered within a flexible planning strategy designed to minimize regional electricity costs and risks.

The forecasts presented in this chapter were developed cooperatively with the Bonneville Power Administration. A number of preliminary drafts were reviewed by Bonneville and Council staff, and by members of the Demand Forecasting Advisory Committee and the Economic Forecasting Advisory Committee. Draft forecasts also were circulated widely for public review and comment and were the subject of a Bonneville public involvement meeting. Although the November draft forecasts were adopted by Bonneville for official purposes, the revised forecasts found in this document have not been officially adopted by Bonneville.

Comments received and findings from internal evaluations resulted in many adjustments to the forecasting assumptions and the demand forecasts. This chapter

contains a summary discussion of the revised forecasts, followed by a description of their underlying assumptions. The forecasts of demand are then discussed in more detail by utility type, and the corresponding forecasts of electricity prices are presented. Finally, the role of the demand forecasts in the rest of the Council's power planning process is explained.

Summary of Results

In 1987, firm sales of electricity to the final consumer in the Pacific Northwest totaled 15,618 average megawatts, or 137 billion kilowatt-hours. The high forecast shows this demand could grow to 29,200 average megawatts by 2010, nearly double current electricity requirements. In more graphic terms, the high implies additional demand by 2010 that equals the electricity consumed by 12 cities the size of Seattle. Under the set of assumptions leading to the low forecast, demand decreases slightly to 15,400 average megawatts, an amount little changed from current requirements. Figure 2-1 illustrates the forecast range in the context of historical sales of electricity.

This large uncertainty about future needs for electricity resources represents an important challenge for energy planning. For the Bonneville Administrator, the future uncertainty of demand is magnified by not knowing how much of the region's demand growth Bonneville will be asked to serve. In addition, Bonneville directly serves a group of electricity-intensive industries that have displayed an alarming degree of instability during the 1980s. The region needs to deal with this uncertainty in a manner that neither prevents the region from attaining rapid growth nor imposes large and unnecessary costs if slower growth occurs.

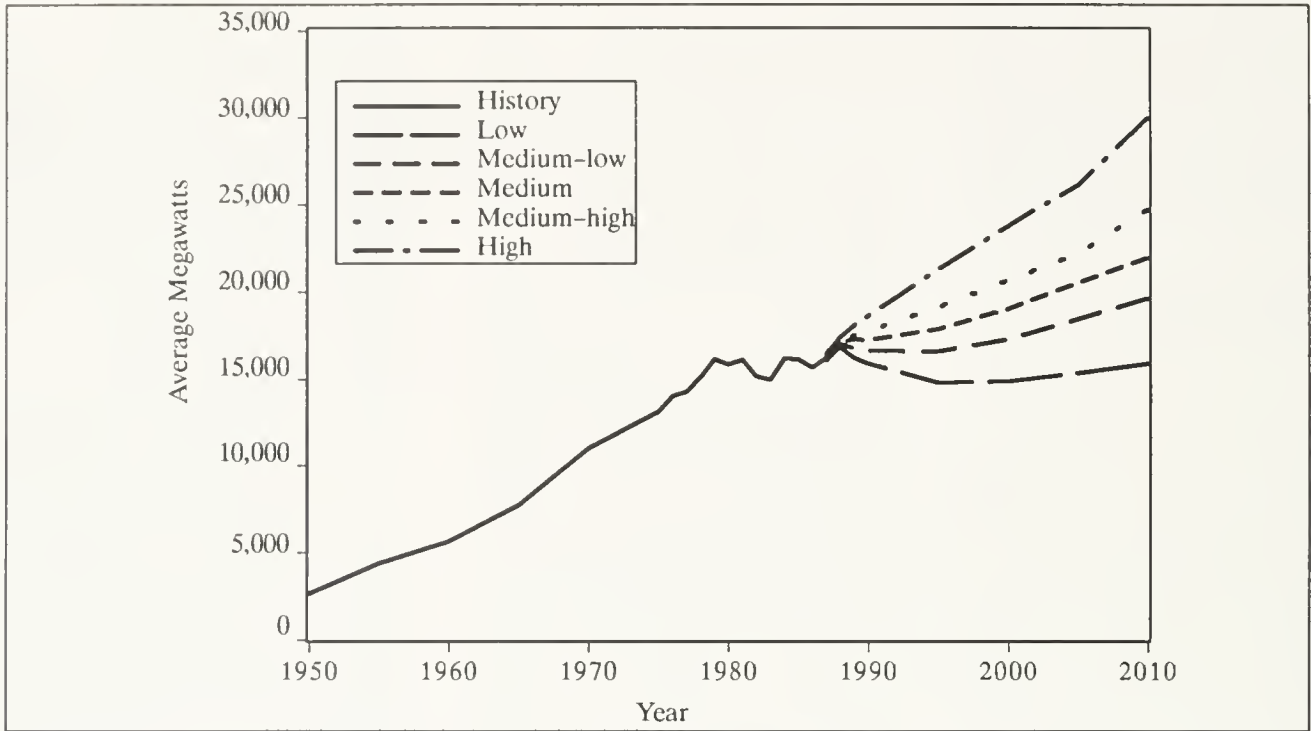


Figure 2-1
Sales of Electricity in the Pacific Northwest
Historical and Forecast

Table 2-1 shows that the rate of growth of demand could be as high as 2.8 percent per year, if the high case materialized, or as low as -0.1 percent. A more likely range for future electricity demand, however, is between the medium-high growth rate of 1.9 percent and the medium-low rate of 0.9 percent. The medium forecast is for a 1.4-percent annual growth rate of electricity demand.¹

A note of caution is warranted. While a medium forecast has been developed as part of the cooperative forecast with Bonneville, it would be a mistake to put heavy reliance on the medium forecast as the most likely future for the region. This would return the region to the old mode of trying to predict the future with pinpoint precision, which proved extremely costly. The acceptance of a

broad range of possibilities is integral to maintaining flexibility and minimizing risk in regional power planning.

Figure 2-2 compares the projected growth rates of demand to growth rates experienced in the region since 1950. Between 1950 and 1970, demand for electricity grew an average of 7.4 percent a year. During the 1970s, demand grew much more slowly, about 3.7 percent per year. Between 1980 and 1986, electricity demand did not increase at all. However, a substantial demand increase occurred in 1987, resulting in the average annual increase of 0.5 percent for 1980 to 1987. While the low forecast represents a continuation of the 1980s pattern, the high forecast is still well below the growth rate experienced in the 1970s and far below pre-1970 growth.

Decreasing growth rates of demand for electricity, historically and in the forecasts, result from many factors. These factors include the rate of growth of the economy, changing standards of living, the price of energy relative to other goods and services, and the changing mix of economic activity, both in the nation and in the region. Many of these factors reduce future electricity demand growth in the United States, and to an even larger degree in the Pacific Northwest. The larger reductions in demand growth in the Pacific Northwest stem, in part, from the unique patterns of electricity use in the region. This difference from the patterns of electricity use in the rest of the nation is illustrated in Figure 2-3, which shows electricity used per capita.

1./ These growth rates are calculated using actual sales in 1987 and forecast sales in 2010. If a different period of years is used, it could result in significantly different rates of growth.

Table 2-1
Firm Sales of Electricity
(Average Megawatts)

	ACTUAL 1987	FORECASTS			GROWTH RATE (% per year) 1987-2010
		1990	2005	2010	
High	15,618	17,751	25,979	29,223	2.8
Medium-high	15,618	17,934	21,915	24,026	1.9
Medium	15,618	16,456	19,853	21,344	1.4
Medium-low	15,618	15,835	17,897	19,124	0.9
Low	15,618	15,170	14,913	15,442	-0.1

Although the historical pattern of growth in per capita electricity use is similar in the region and the nation, there is a striking difference in the amount of electricity used. The Pacific Northwest uses nearly twice as much electricity per person as the nation as a whole. This is due primarily to large supplies of low-

cost hydroelectric power in this region. This low-cost power has led to electricity-intensive industry locating in the region and to heavy use of electricity in other sectors as well. Recent large increases in the Northwest price of electricity, however, have changed the

outlook for electricity demand. The forecasts show that, while per capita electricity use will remain well above national levels, it will not continue to grow except in the high forecast, and could actually decline significantly in the lower forecasts.

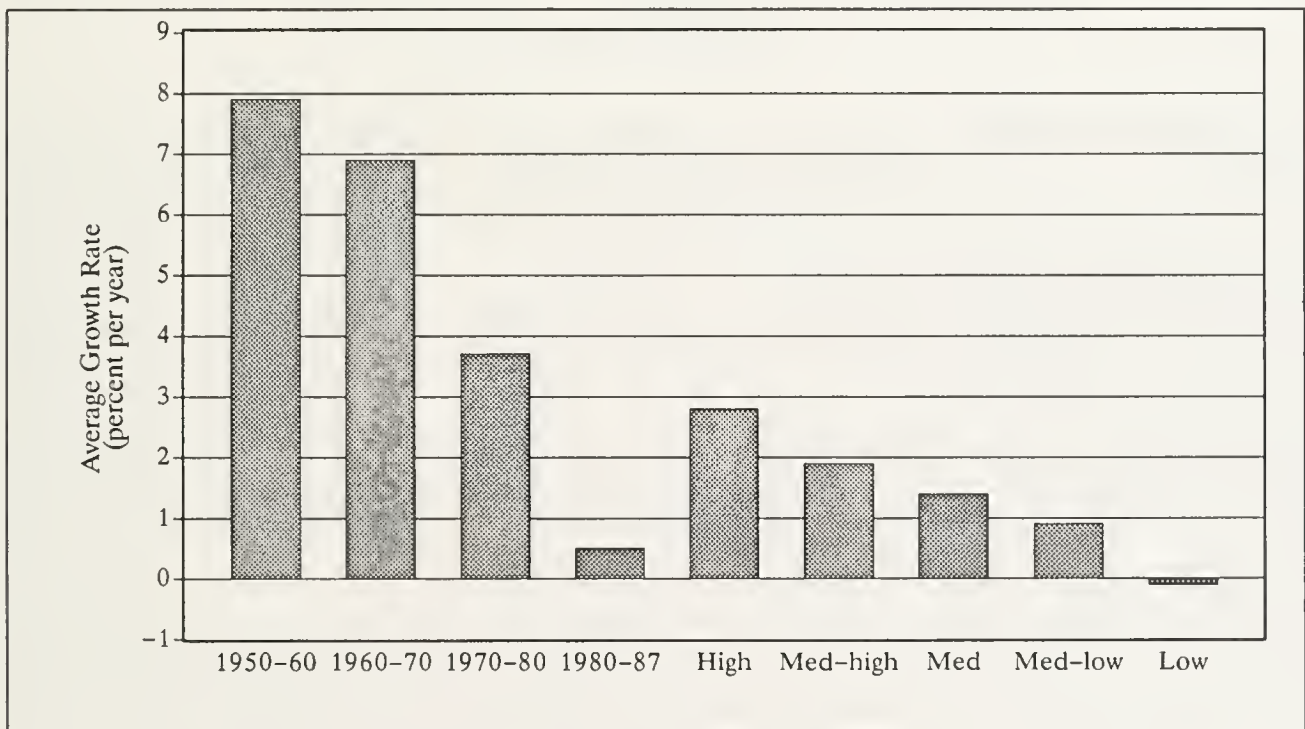


Figure 2-2
Historical and Forecast (1987-2010) Growth Rates

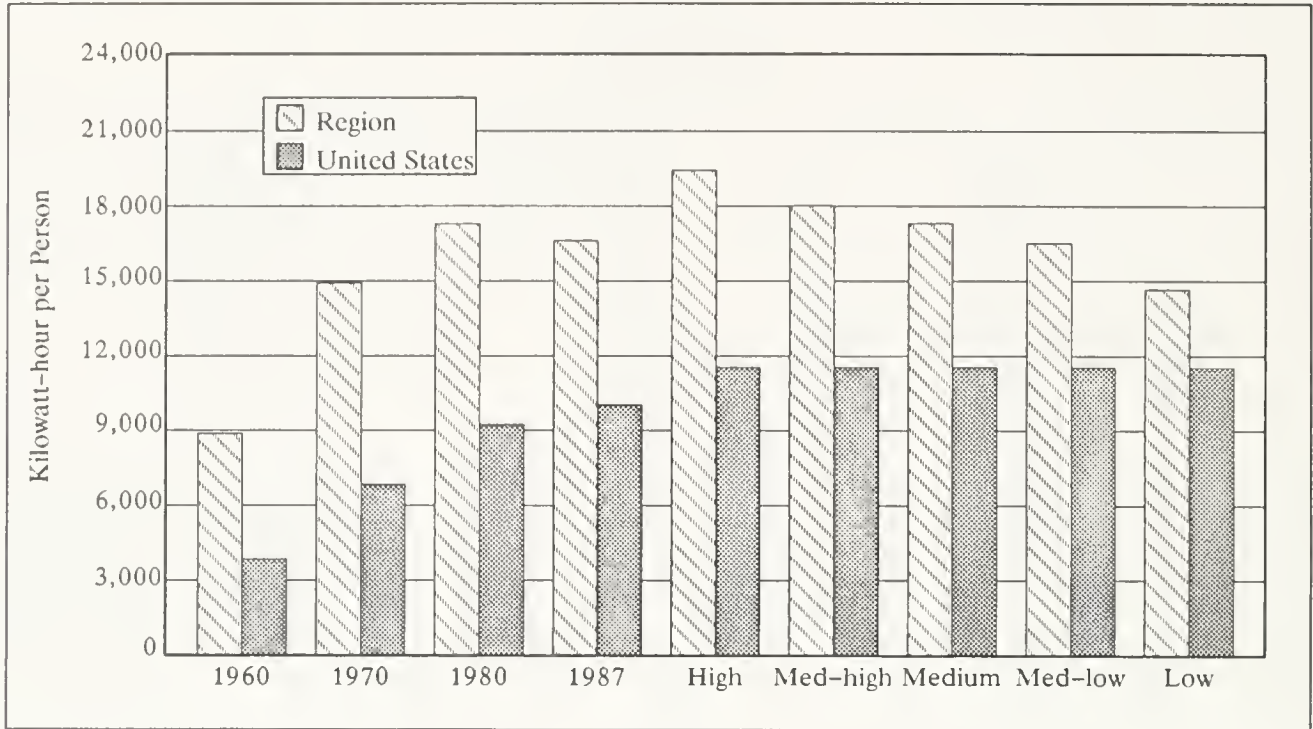


Figure 2-3
Electricity Use per Capita
 (Region vs. U.S., History and Forecasts for 2010)

Economic and Demographic Assumptions

Economic and demographic assumptions are the dominant factors that influence the forecasts of demand for electricity. In the absence of other changes, the demand for electricity would parallel economic activity. This relationship is modified by shifts in relative energy prices, including the price of electricity and other fuels; by changes in the composition of economic activity; and by the gradual depreciation and replacement of

buildings and equipment in the region that use electricity. Conservation programs implemented by the region will further affect future sales of electricity.

The range of forecasts in this supplement resembles in many respects the forecasts incorporated in the 1986 Power Plan. The high forecast allows the Council's plan to accommodate record regional economic growth, should it occur. In the high forecast, total regional employment grows 65 percent faster than a high national forecast of employment. The high forecast represents a case in which

the region grows faster, relative to the nation, than in any historical 20-year period. The low forecast assumes that the Pacific Northwest grows at a rate 40 percent lower than a low-growth national forecast. The low case implies a relative performance well below that which has characterized the region in the long term. Figure 2-4 compares the region's total employment growth with U.S. growth rates. Table 2-2 compares historical and forecast growth rates for total employment for the Northwest and the nation.

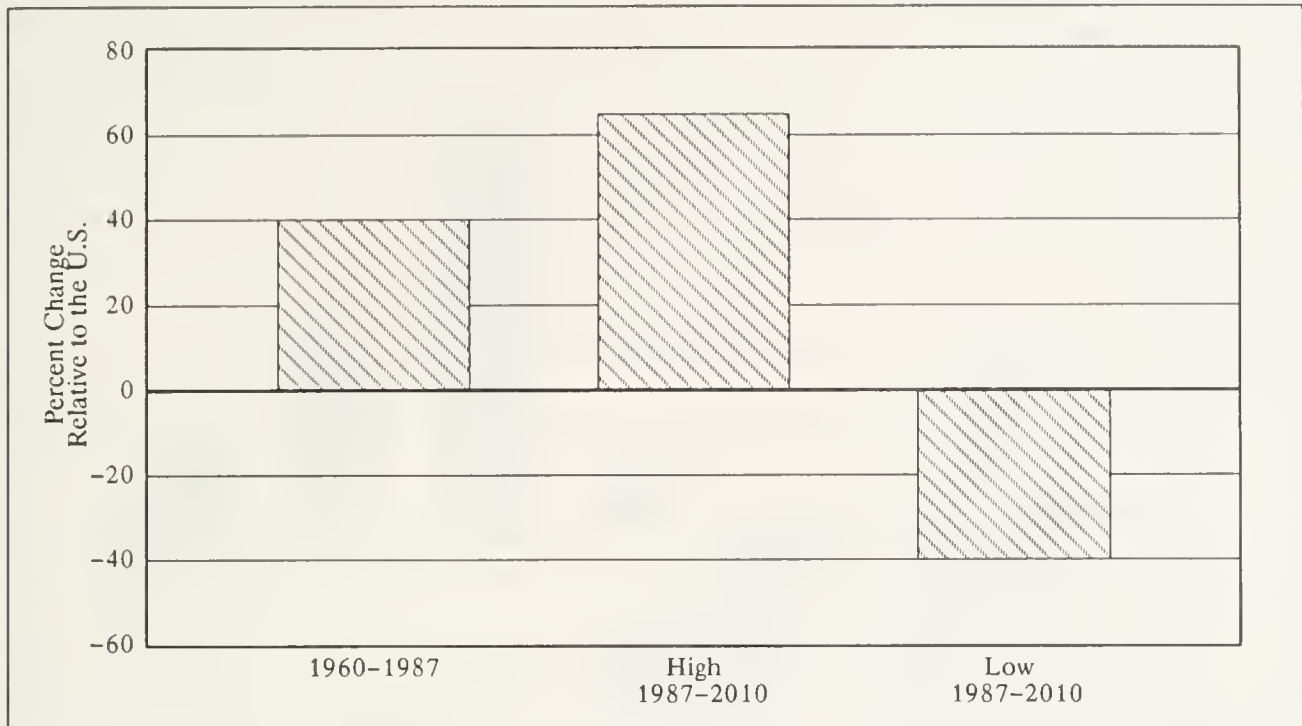


Figure 2-4
Pacific Northwest Employment Growth
Relative to the United States

Table 2-2
Total Employment Growth Comparisons
(Percent per Year)

	PACIFIC NORTHWEST	UNITED STATES	RATIO
Historical 1960-1987	2.8	2.0	1.4
Forecast (1987-2010)			
High	2.8	1.7	1.6
Low	0.4	0.7	0.6

Major Trends

There are a number of basic trends common to the range of forecasts. Many of the trends relate to demographic patterns in the existing population.

One primary change is the aging of the population. As shown in Figure 2-5, the

nation's total population is expected to increase 20 percent between 1987 and 2010. The population in the 45-59 age group, however, is expected to increase more than 80 percent, while the population aged 25-34 is projected to decline more than 10 percent. The population older than 60 is projected to increase 37

percent during this period. Although the age composition in the region will vary among scenarios because of migration, the general patterns of demographic change will persist. Figure 2-5 shows the percentage change in population by age group for the nation from 1987 to 2010.

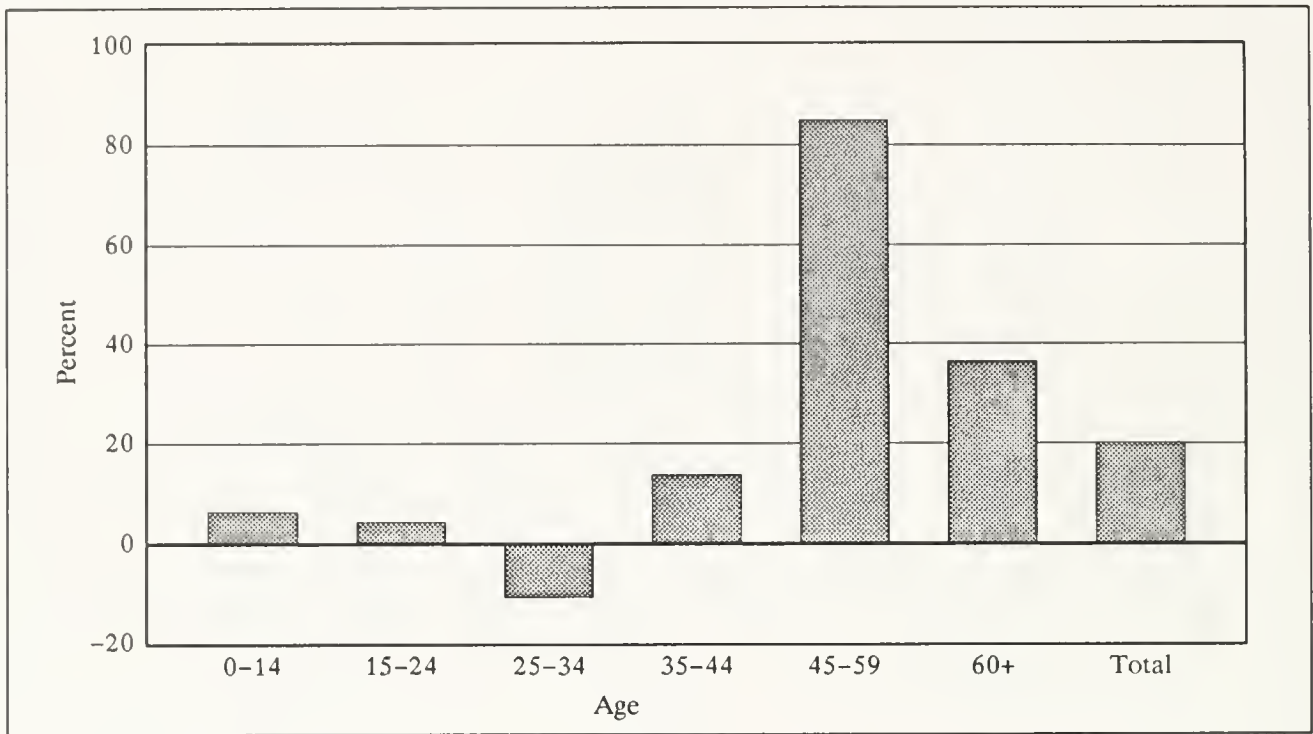


Figure 2-5
Percentage Change by Age Group (1987-2010)

This aging of the population is expected to affect consumption patterns, the labor force and labor productivity. Consumption patterns are expected to emphasize personal services, clothing, travel and health services, as the older population increases in size. Over the next 20 years, the number of young people entering the labor force will increase at a slower rate than historically. From 1987 to 2010, the population aged 15-24 is projected to increase at an average annual rate of only 0.2 percent, while from 1970 to 1980, the population in this age group increased at an average annual rate of 1.8 percent. This is the primary reason that the labor force is projected to increase at a slower rate over the next 20 years than historically. The tightening labor supply will put upward pressure on wages. Producers will seek to substitute capital for labor, which tends to increase productivity, or output per employee. In addition, the rapid pace of technological change and continuing pressure of international

competition will stimulate capital investment as well.

A second major trend is the increase in the percentage of women who work. From 1960 to 1987, this proportion increased from 37 percent to 57 percent. This trend is expected to continue to varying extents in all forecasts.

Continued growth in the importance of non-manufacturing industries is projected throughout the forecast range. Traditionally, studies of regional economic growth have focused on the manufacturing industries. Recently, the non-manufacturing industries have attracted more attention because of their size and rapid growth. In 1987, non-manufacturing industries accounted for 84 percent of total employment in the region. Non-manufacturing employment increased at a rate nearly 70 percent faster than manufacturing employment from 1960 to 1980.

The outlook is strong for industries, such as communications and machinery, that will play a key role in growing technological change and productivity-enhancing investments. The foreign trade sector is expected to continue to increase in importance. The West Coast is well positioned to participate in trade to the Pacific Rim countries, and given the crowding and high costs in California, the Pacific Northwest could experience a growing share of that trade. That possibility is an important component of the higher growth forecasts.

Slower growth in the region's large resource-based industries characterizes the whole range of forecasts. Lumber, paper, aluminum and food products are not expected to be important sources of economic growth for the region, even in the high forecasts.

Description of the Scenarios

The economic and demographic assumptions rely on basic policy assumptions,

many of which operate at the national level. Each of the five regional economic forecasts, while built up from regional assumptions about individual sectors of the economy, was made within the context of a corresponding view of the na-

tional economy. The forecasts include a wide range of possibilities for the regional economy. For example, there could be nearly 75 percent more jobs in the region by 2010 in the high case than in the low case. Figure 2-6 shows the employment

forecasts in the high and low cases. Forecasts developed by Wharton Econometric Forecasting Associates (Wharton)² were the primary source for forecasts of national economic variables used in developing regional projections.

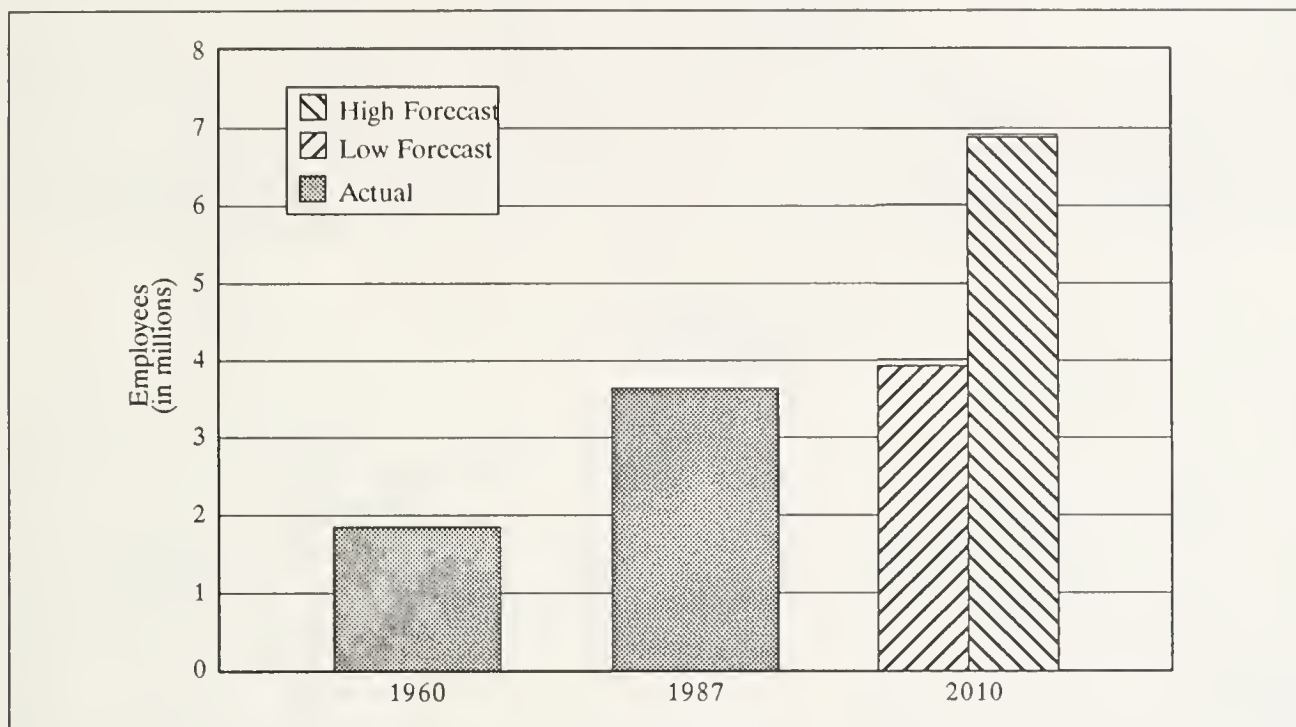


Figure 2-6
Forecasts of Total Employment

High-Growth Case

In addition to an underlying high-growth scenario on the national level, the regional outlook for the high-growth case implies that the region's economy may fare better, relative to the nation, than it has in the past. Large resource-based industries, such as forest products, aluminum, agriculture and basic chemicals, are expected to maintain a vital presence in the region's economy in the high forecast, but not contribute new jobs. Industries such as electronics, trade and services could expand rapidly.

As shown in Table 2-2, high forecast total employment is projected to increase 2.8 percent per year, which is similar to the region's growth rate in 1960-1987. Population would grow 2 percent, while the number of households would increase 2.7 percent per year. It is assumed in these projections that the region will continue to be a favorable location for growth, because of the richness and diversity of its natural resources, the quality of its environment, labor force and educational system, low electricity prices relative to other regions, and proximity

to expanding markets in Japan and other Pacific nations.

Medium-high-Growth Case

Rapid growth in high-technology and commercial industries, coupled with moderate levels of activity in forest products, agriculture and basic chemicals, characterize the medium-high case. This anticipates employment growth of 2.1 percent per year, and population and household growth of 1.5 percent and 2.0 percent per year, respectively. Although the overall level of employment growth

2./ Wharton Econometric Forecasting Associates, *Long-term Alternative Scenarios and 25-year Extension*, August 1987 and February 1988.

in the medium-high scenario would be slower than the region experienced in the 1960s and 1970s, it still would be 75 percent faster than the forecast of national growth in the medium case.

Medium-Growth Case

Manufacturing employment would not increase in the long term in the medium case. New jobs would come from the non-manufacturing sector. Total employment would increase 1.6 percent per year, with population and households ex-

pected to increase 1.2 percent and 1.6 percent per year, respectively.

Medium-low-Growth Case

Traditional industries would experience low levels of economic activity, while commercial industries would experience moderate growth levels in the medium-low forecast. Total employment is projected to increase 1.1 percent per year, with population and households expected to increase 0.9 percent and 1.3 percent per year, respectively, as shown in Table 2-3. In the medium-low scenario, employment growth would be slightly

slower than national growth in the medium case.

Low-Growth Case

The regional outlook for the low case shows total employment could increase 0.4 percent per year, indicating a rate 40 percent below the low forecast of national growth. Total population is projected to increase 0.4 percent per year and households 0.4 percent. This slow level of growth implies the region's outmigration will top natural population growth throughout the forecast period.

*Table 2-3
Summary and Comparison of Economic Forecasts
Pacific Northwest and U.S.*

	AVERAGE ANNUAL RATE OF CHANGE (%)							
	1960-1980		1987-2010					
	U.S.	PNW	U.S. ^a	MEDIUM-HIGH	HIGH	MEDIUM	MEDIUM-LOW	LOW
Total Employment	2.1	3.1	1.2	2.8	2.1	1.6	1.1	0.4
Manufacturing	1.0	2.0	-0.3	1.3	0.5	0.0	-0.5	-1.3
Non-manufacturing	2.4	3.4	1.5	3.1	2.4	1.8	1.3	0.6
Population	1.1	1.9	0.8	2.0	1.5	1.2	0.9	0.4
Households	2.1	2.8	1.4	2.7	2.0	1.6	1.3	0.4

^a The U.S. forecast is Wharton's August 1987 medium-case projection.

Alternative Fuel Prices

Because natural gas and oil compete directly with electricity, their future prices can have important effects on the demand for power. That competition is particularly important in residential and commercial building space and water heating.

Forecasts of demand for electricity are less sensitive to fuel price assumptions than to economic and demographic assumptions. A doubling of fuel prices will cause only about a 5 percent increase in

electricity demand. Nevertheless, fuel prices contribute significantly to the demand forecast range, because there is such a wide range of uncertainty about future fuel prices.

Future retail natural gas and oil prices are expected to be influenced by trends in the world price of crude oil. The forecasts of wholesale prices of refined petroleum products are based on a range of world oil price assumptions. The forecasts of prices of natural gas are based on its competition with oil in industrial markets. Various retail mark-ups are

applied to estimate retail prices for consuming sectors.

World oil prices could increase by as much as 5.1 percent per year faster than the rate of general inflation between 1987 and 2010. However, it is also conceivable that oil prices could be little different from current levels by 2010, with substantial reductions in the early years of the forecast. Figure 2-7 illustrates the range of world oil price assumptions. The highest assumption for oil prices is in the high electricity-demand forecast, and the lowest oil price is assumed in the

low-demand forecast. (Chapter 1 in Volume II of this supplement, "Economic Forecasts for the Pacific Northwest," provides more detail on these assumptions.)

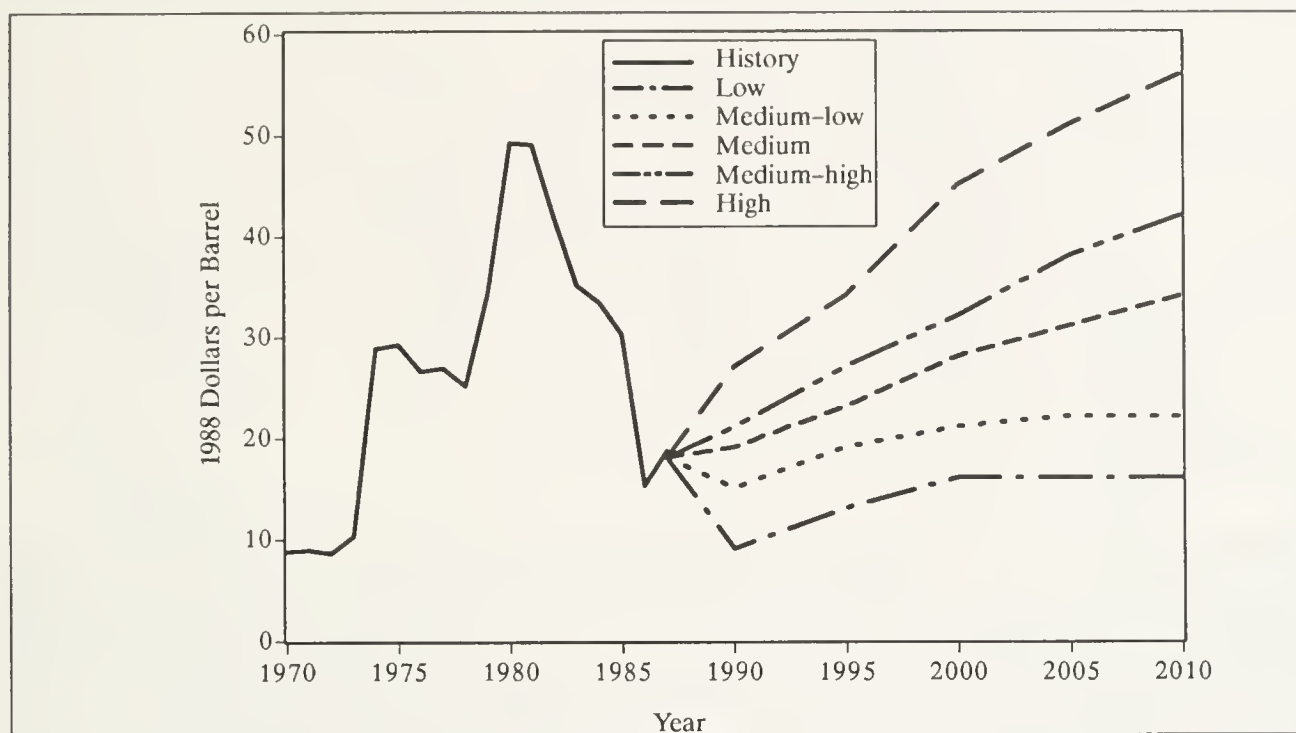


Figure 2-7
Forecasts of World Oil Prices

Table 2-4 compares world oil price assumptions with an estimated 1987 price. All the prices are shown in 1988 dollars. The low forecast assumes that prices will collapse further, recover to only \$16 per barrel by the end of the century and remain at that level thereafter. This scenario would be consistent with very favorable oil and natural gas supplies and with significant progress having been made in improved energy efficiency, even with low price incentives. Under such conditions, the Organization of Petroleum Exporting Countries (OPEC) would not be able to effectively control world oil markets.

In the high scenario, prices approach \$26 a barrel by 1990 and continue to make significant real gains, reaching \$56 by 2010. Such price rises could take place if OPEC regains control of oil markets.

That could happen if little new oil and gas is discovered and if efficiency improvements are slow in coming. The medium-low and medium-high forecasts bound a more likely long-term range that spans from \$22 to \$42 per barrel in 2010. The medium forecast shows world oil prices growing gradually at 2.8 percent per year from current levels, reaching \$34 per barrel by 2010.

The proposed range of oil price assumptions is significantly lower than that used for the Council's 1986 Power Plan. Shortly after the Council published the 1986 plan, world oil prices collapsed to less than half their previous levels. In many analysts' minds, this demonstrated that oil prices above \$30 per barrel are not sustainable for long. But the relatively quick rebound of oil prices from their 1986 low back to \$17 has led some to

conclude that \$17 to \$20 may represent a sustainable range for the next several years, although significant volatility can be expected.

Changes in the price of a barrel of oil translate into various price changes for different petroleum products. How much a change in the price of a barrel of oil will impact electricity demand depends on retail prices of oil and natural gas, retail prices for electricity and how those prices change relative to one another. Forecasts of electricity prices are determined by demand forecasts. Higher demand for electricity eventually leads to higher electricity prices, as more expensive new resources must be used to meet growing demands. Therefore, electricity prices in the year 2010 are highest in the high-demand case. However, when viewed relative to oil and nat-

ural gas prices, the price of electricity is lowest in the high forecast. This stimulates demand for electricity as a fuel

choice in the high forecast. The converse is true for the low scenario. In general, because of the reduced level of oil and

gas prices in this forecast, natural gas is more competitive with electricity than in the 1986 plan forecast.

Table 2-4
World Oil Prices
(1988 Dollars per Barrel)

	LOW	MEDIUM- LOW	MEDIUM	MEDIUM- HIGH	HIGH
Prices					
1987	18	18	18	18	18
2000	16	21	28	32	45
2005	16	22	31	38	51
2010	16	22	34	42	56
Growth Rates					
1987-2010	-0.5	0.9	2.8	3.8	5.1

Demand Forecasts

The summary of forecast results in this document tends to hide the fact that the Council's forecasts are done in great detail. A major dimension of the demand analysis system is the separate forecasting of residential, commercial, industrial and irrigation uses of electricity. A second major dimension is the separate treatment of demand by customers of public utilities, Bonneville and investor-owned utilities. Further, most components of demand, such as residential use of electricity in investor-owned utility service areas, are analyzed for specific end uses as well as other dimensions within the sector forecasting models. The sector and end-use details are discussed in Volume II, Chapter 1 of the supplement. The sectoral and utility ownership dimensions are characterized briefly below.

Separate forecasts are done for investor-owned utilities, public utilities, and Bonneville customers. The economic assumptions driving the forecasts are divided into investor-owned and public utility service areas, described in Volume II, Chapter 1. These economic assumptions, combined with differences in elec-

tric rates and existing conditions, lead to differences in the forecasts for the two customer groups.

In 1987, total regional firm sales of electricity were 15,618 average megawatts. Investor-owned utilities marketed 7,318 average megawatts, or 47 percent of the total. Public utilities marketed 39 percent, and Bonneville directly marketed 14 percent of firm sales. Table 2-5 shows the 1987 composition of firm sales and the five forecasts for 2010.

Table 2-5 shows the public utility and Bonneville sales separately. Direct service industries (mainly aluminum companies) accounted for most of Bonneville's direct sales in 1987, but are forecast to increase only moderately from 1987 levels in the higher cases and decrease in the other forecasts. Public utility sales are projected to grow more slowly than investor-owned utility sales in three of the five forecasts.

In addition to providing electricity directly to some customers, Bonneville is the source of much electricity sold by public utilities. Although several public utilities generate electricity themselves to serve part of their loads, most public utilities rely entirely on Bonneville. There-

fore, the Administrator's obligations consist of: 1) direct service industrial customers and various federal agencies that are served directly by Bonneville; 2) most loads of publicly owned utilities that have no electricity resources (non-generating publics); and 3) a part of the loads of publicly owned utilities that have electricity resources (generating publics). In Figure 2-8, Bonneville-supplied electricity is the shaded area. Bonneville supplied about 40 percent of the firm electricity sales in the region in 1987.

Forecasting the growth of Bonneville's obligations is complicated by unknowns well beyond the basic uncertainty embodied in forecasts of regional electricity demand. Figure 2-9 helps illustrate the nature of uncertainty facing the Administrator. The figure shows the forecast range of regional demand as the upper wedge. Below the regional range is an unshaded range of growth forecasts for current Bonneville customers. Added to this basic Bonneville uncertainty is a shaded area representing potential demands that could be placed on Bonneville with seven years' notice. The shaded area is the growth in privately owned utility demands beyond their current resources.

Table 2-5
Firm Sales Forecast by Utility Type
(Average Megawatts)

	TOTAL SALES	INVESTOR-OWNED UTILITY SALES	PUBLIC UTILITY SALES	BONNEVILLE DIRECT SALES
Actual 1987	15,618	7,318	6,047	2,253
Forecast 2010				
High	29,223	15,124	11,434	2,664
Medium-high	24,026	12,115	9,536	2,375
Medium	21,344	10,748	8,510	2,085
Medium-low	19,124	9,503	7,887	1,734
Low	15,442	7,632	6,428	1,382
Growth rates 1987-2010				
High	2.8	3.2	2.8	0.7
Medium-high	1.9	2.2	2.0	0.2
Medium	1.4	1.7	1.5	-0.3
Medium-low	0.9	1.1	1.2	-1.1
Low	-0.1	0.2	0.3	-2.1

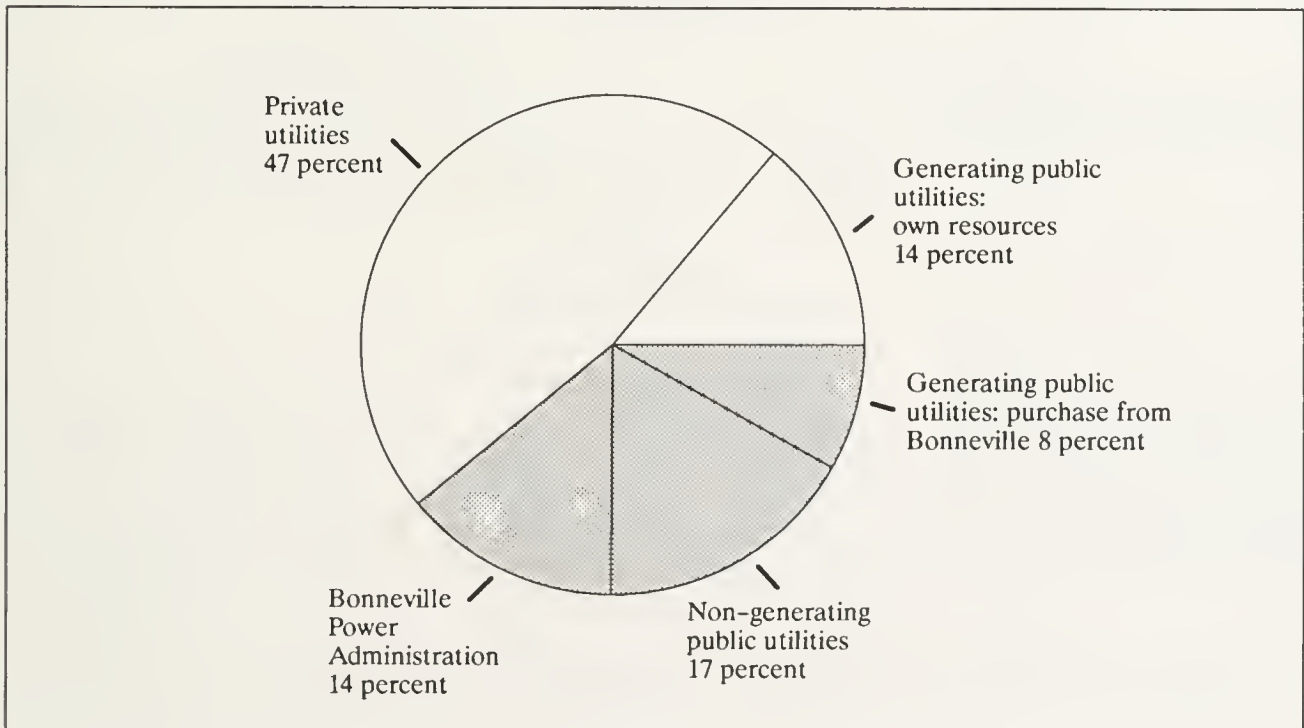


Figure 2-8
Regional Firm Sales by Utility Type
(Bonneville's Current Obligation Shaded)

As can be seen from Figure 2-9, Bonneville's uncertainty is essentially the same size as the region's. In relative terms, however, it is much greater. A relative measure of uncertainty, for example, might be the relationship of the high forecast to the low forecast. For the re-

gion, the high forecast is 90 percent above the low forecast. For Bonneville's current customer base, the high forecast is 120 percent above the low. Therefore, even without the additional risk of private utility load growth, Bonneville's uncertainty is greater than that facing the

region as a whole. This is largely due to the substantial downside risk associated with the direct service industries. With the potential placement of private utility load growth on Bonneville, the Administrator's high would be 260 percent above the low.

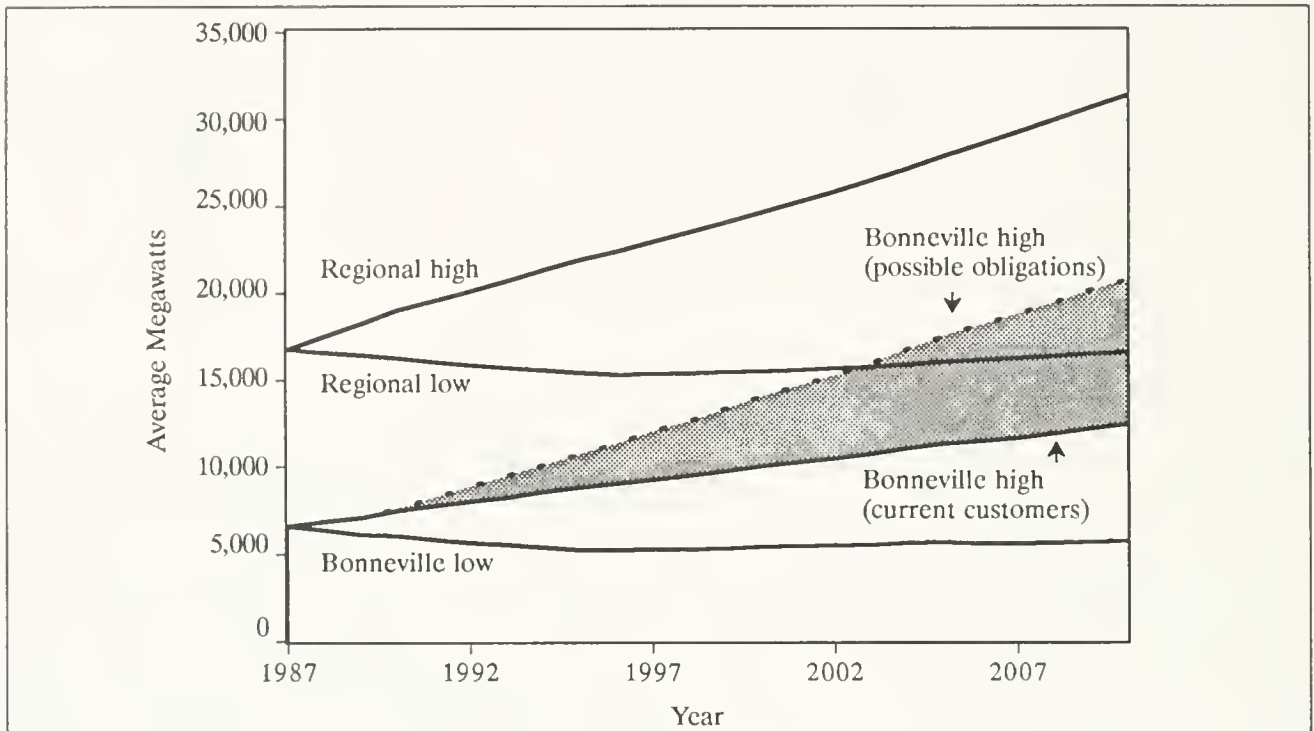


Figure 2-9
Regional and Bonneville Uncertainty

The Administrator also faces additional downside risk that is not reflected in the Bonneville low forecast shown above. That additional risk is that public utilities increasingly could build their own resources, thereby gaining a measure of independence from Bonneville.

Figure 2-10 shows the composition by sector of the 1987 electricity sales in the region. The industrial sector accounts for the largest share of electricity sales, followed by the residential and the commercial sectors. Those three sectors account for 95 percent of the region's electricity demand. Forecasts for each of

the demand sectors is discussed in detail in Volume II, Chapter 2.

Electricity Prices

The Council's forecasts show relatively stable electricity prices over the next several years in the Pacific Northwest. The exact price outlook, however, varies substantially in the various forecasts, due to different amounts of new resources that must be acquired. Because nearly all new resources cost more than the existing resource base, adding new sources of power will raise electric prices. Figure 2-11 shows the five price forecasts. The prices in Figure 2-11 are real average retail prices in 1988 dollars.

As can be seen from Figure 2-11, retail prices are projected to decline in real terms after 1987. This decline reflects the shrinking surplus, as electricity sales grow and fixed costs are spread over more sales. This expected pattern does not include the effects of recent drought conditions and depressed nonfirm power sales and prices, both of which tend to keep prices higher. In each forecast scenario, electricity prices are expected to increase as new resources are needed to meet growing demands. This does not occur in the low case because there is little need for additional resources.

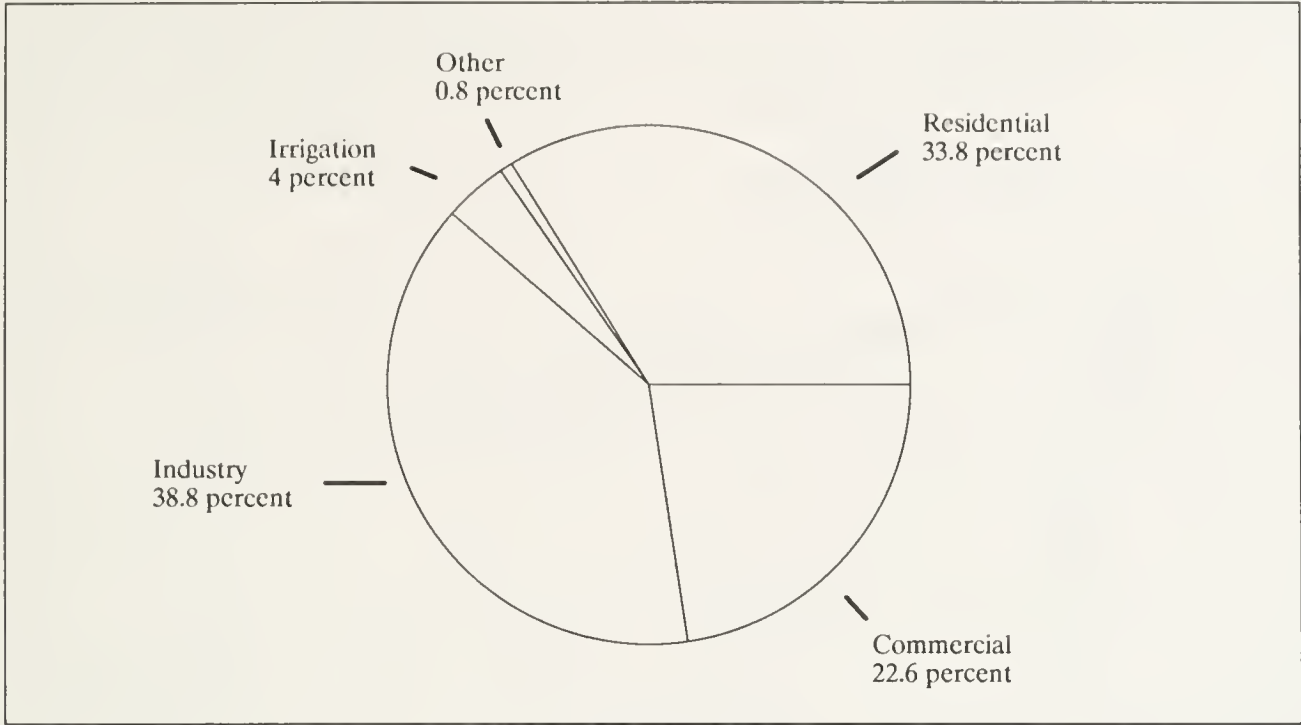


Figure 2-10
1987 Firm Sales Shares

Table 2-6 shows estimated 1987 electricity prices, forecast prices for 2010 and average annual rates of change for three

different kinds of prices. The table outlines predictions of average retail prices paid by all consumers combined, by cus-

tomers of public utilities and by customers of investor-owned utilities.

Table 2-6
Electricity Price Forecasts
(1988 Cents per Kilowatt-hour)

	AVERAGE RETAIL ALL CONSUMERS	AVERAGE RETAIL PUBLIC UTILITIES	AVERAGE RETAIL PRIVATE UTILITIES
Estimated 1987 (1988 cents per kWh)	3.9	3.4	4.7
Forecast 2010 (1988 cents per kWh)			
High	4.4	3.7	5.3
Medium-high	3.9	3.1	4.8
Medium	3.7	3.0	4.6
Medium-low	3.4	2.6	4.2
Low	3.3	2.4	4.3
Growth Rates (% per year) (1987-2010)			
High	0.5	0.5	0.5
Medium-high	0.0	-0.3	0.1
Medium	-0.2	-0.5	-0.1
Medium-low	-0.7	-1.0	-0.5
Low	-1.3	-1.7	-0.4

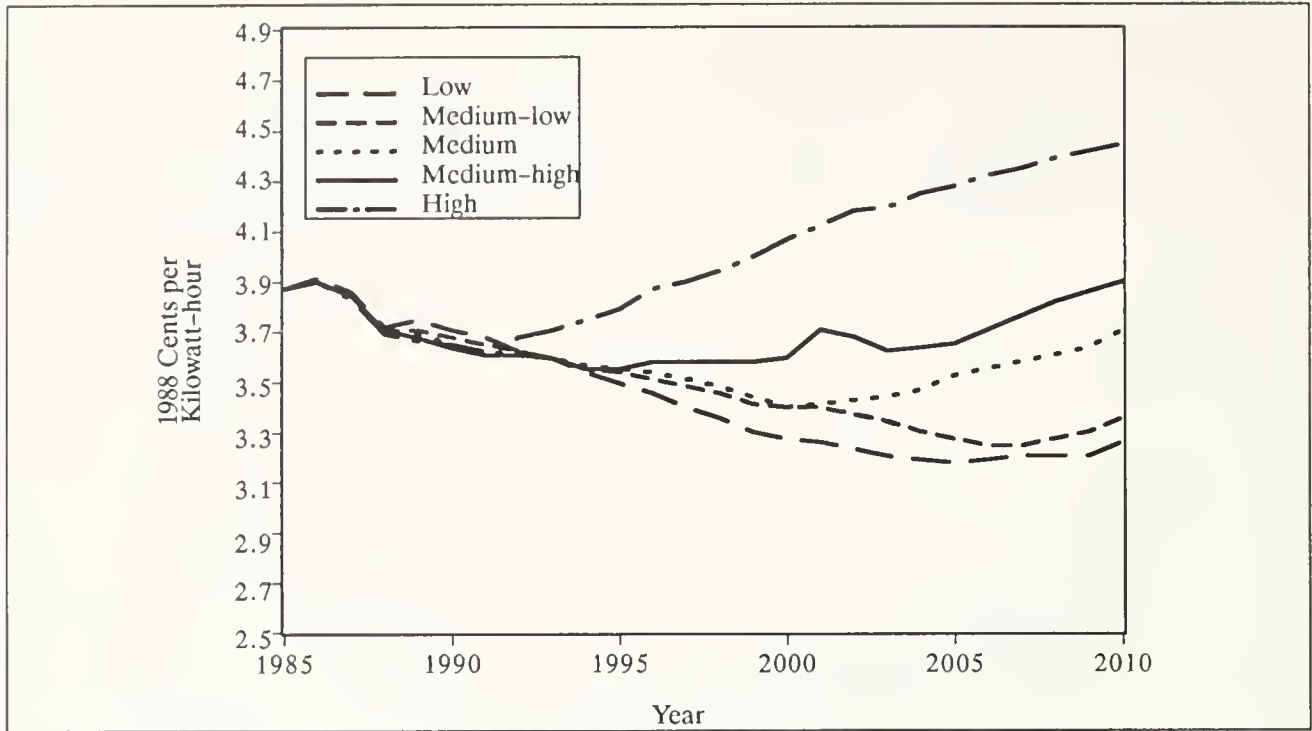


Figure 2-11
Average Retail Electric Prices

Average retail electric prices in the region are predicted to increase faster than inflation between 1987 and 2010, in the high forecast. In the medium-high and medium cases, real prices should remain about the same in 2010 as in 1987, and in the low and medium-low forecasts, real prices decline. Private utility prices are projected to increase faster or decrease less than prices for publicly owned utilities, in most cases. This is because private utilities need to add new resources sooner than public utilities.

These results depend on an assumption about the resource portfolio that will be used to meet future demand growth. The portfolio will be modified following a more detailed regional discussion and analysis of resource alternatives over the next two years. Another important assumption is that no dramatically revised repayment requirement will be imposed for the federal debt on the region's hydroelectric system. Some of the more ex-

treme versions of the revised repayment costs would have a significant effect on electricity prices. Other assumptions are described in Volume II, Chapter 2.

Demand Forecasts in Resource Planning

The role of demand forecasts in the Council's resource planning is significantly different from their traditional role. Demand forecasts traditionally could be characterized as deterministic. That is, a "best-guess" demand forecast determined the amount of new electricity generation needed. Before the early 1970s, utility planners generally assumed that demand for electricity would continue to grow at close to historical rates. That growth had been rapid and relatively steady. They assumed that economies of scale in power generation could be relied on to keep electricity prices from increasing as new generating plants were added. Planners saw little reason for de-

mand growth to slow. In fact, they assumed that there would be little or no market response to higher prices.

The dramatic reduction in demand growth that occurred after electricity prices rose in the early 1970s surprised most planners. They responded by developing much more sophisticated forecasting tools. The forecasting models adopted by the Council represent the results of those efforts. However, the Council has recognized that even with the best available models, forecasts of future demand remain highly uncertain. This recognition moves forecasts away from the deterministic role in planning to what may be described as an integral role.

The structure of the demand forecasting system and its relationship to other power planning activities is illustrated by Figure 2-12. The figure illustrates that resource choices affect the demand forecast, both through the direct effects of

conservation on demand, and through the indirect effect of resource costs on electricity prices. Demand forecasts are no longer an independent preliminary

action to resource planning, but directly affect, and are affected by, resource costs and decisions. The manner in which demand forecasts have been integrated

into the Council's resource planning is described in more detail in Volume II, Chapter 2.

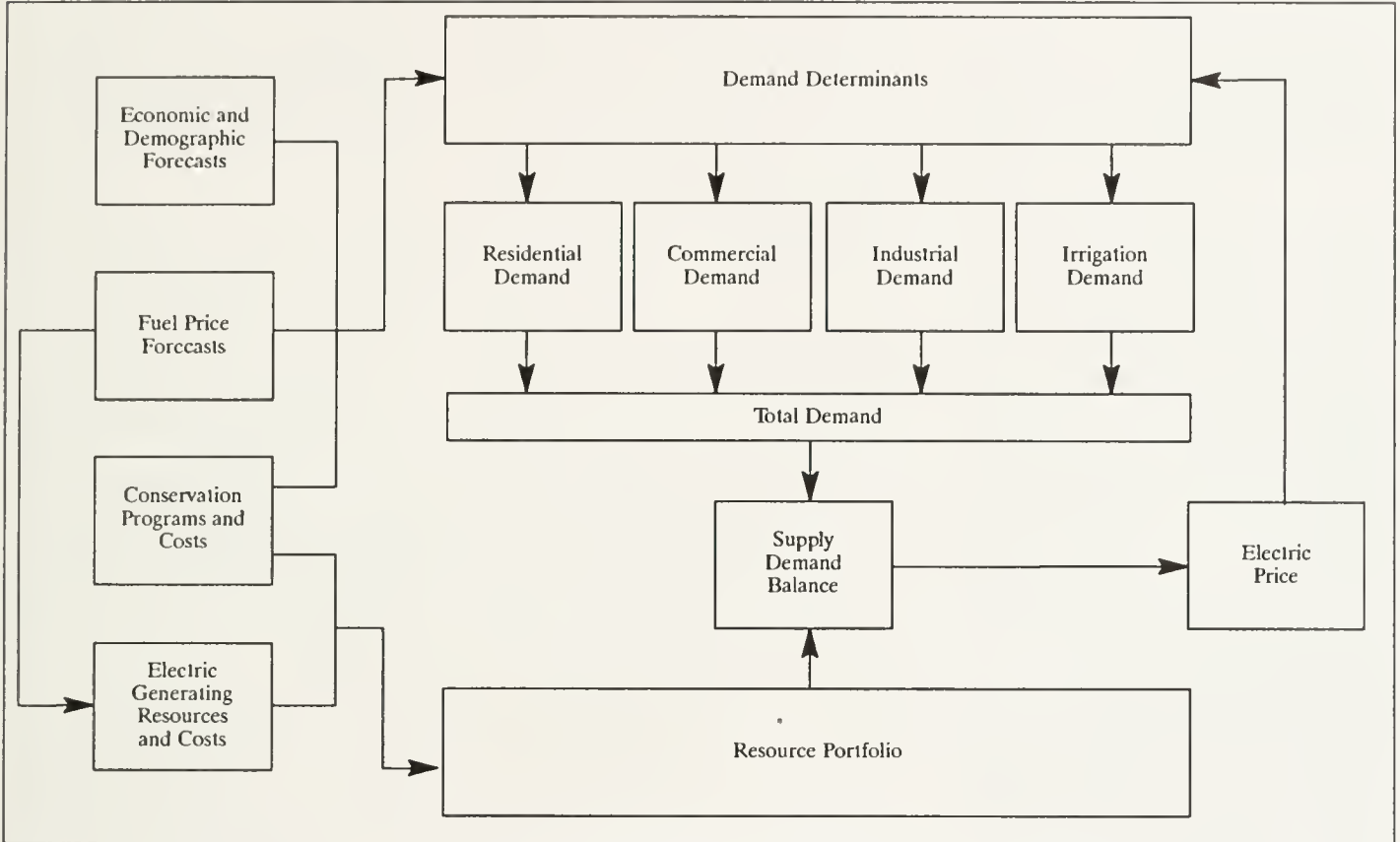


Figure 2-12
Demand Forecasting System

Chapter 3

Conservation Resources

Conservation is a key resource for meeting the Northwest's future electrical energy needs. Each megawatt of electricity conserved is one less megawatt that needs to be generated. The Council has identified almost 2,540¹ average megawatts of achievable conservation in the high-demand forecast available at an average cost of 2.4 cents per kilowatt-hour. This is enough energy to replace almost six large coal plants, and at less than half the cost.

While the conservation estimates presented in this chapter are based on the most recent information available, there is a great deal of uncertainty surrounding the exact amount that could be secured over the next 20 years. This uncertainty is particularly true for the commercial and industrial sectors, where there is significantly less information than in the residential sector. While the Council is committed to updating all the estimates of conservation potential on a regular basis, the commercial and industrial sectors merit the first efforts.

At the time this supplement was adopted, the Council was in the process of revisiting the existing commercial model conservation standards (MCS) (adopted in 1983) in an attempt to strengthen the standards to capture all cost-effective conservation. It was anticipated that the new commercial standards would contain two key components: a strengthened commercial code and programs to secure all remaining measures that are cost-effective. Programs are especially important because it is unlikely that building codes can be written to incorporate all cost-effective savings for the vast array of building types that make up the commercial sec-

tor. This investigation into the commercial conservation resource will also provide an opportunity to refine the conservation estimates presented in this chapter. For example, some public comment has indicated that the modeling used to estimate all cost-effective commercial conservation measures omitted such advancements as new lighting technologies. This point needs to be investigated further, because such changes could increase substantially the current estimates of conservation from new commercial buildings. This increase would likely be at least an additional 300 average megawatts.

In both the industrial sector and the existing commercial sector, work needs to be done over the next few months to determine what portion of the full cost-effective resource constitutes a lost opportunity, which should be secured now. In addition, work needs to be done in the industrial sector, because this sector's savings appear to be small in relation to other sectors. The existing commercial data base also merits attention, since the estimates do not reflect the most recent changes in technologies, such as lighting.

In the Council's plan, conservation refers to the more efficient use of electricity—not curtailment—that results in the reduction of consumption. This means that less electricity is used to support the same level of amenity or production that existed before the conservation measure was implemented. Conservation resources are measures² that enable residential and commercial buildings, appliances, and industrial and irrigation processes to use energy efficiently. For example, buildings that cut down heat

loss through insulation and tight construction require less electricity for heating. These "savings" of electricity mean that fewer power plants need to be built to meet growing demand. Conservation also includes measures to reduce electricity losses in the region's generation, transmission and distribution systems. These latter conservation resources are discussed in the following chapter on generating resources.

Conservation is also a uniquely flexible resource. Some conservation programs automatically match growth in electrical demand. Such is the case when new buildings are mandated by code to be energy-efficient. Each new building adds load to the electrical system, but can also save energy if it is better insulated than current practice. Thus, if the economy grows rapidly, the conservation resource expands quickly; but if the economy slows, the conservation resource automatically tracks the more slowly growing loads. Conservation can also be developed more quickly than generating resources when more electricity is required. However, some cost-effective conservation resources could be lost to the region forever if not secured at the appropriate time. The plan refers to these as "lost-opportunity" or "non-discretionary" conservation resources. The most obvious example of a lost-opportunity resource is energy efficiency in new buildings. If buildings don't incorporate conservation measures at the time of construction, it is much more costly—and with some measures impossible—to retrofit them later.

1./ To be consistent with evaluations in the resource portfolio, the value reported here has been decreased for market penetration and increased by 7.5 percent to reflect avoided line losses in the transmission system. In the remainder of this chapter, the reported average megawatt savings have not been adjusted for this line-loss credit. However, the costs in the average levelized cost calculations have been increased for administration expenses and decreased for transmission and distribution cost savings. The savings used in the average levelized cost calculations include the transmission and distribution line-loss savings.

2./ A "measure" means, as appropriate, either an individual action or a combination of actions.

Comparison of Conservation Estimates from the 1986 Plan

The 1986 Power Plan estimated that about 4,300 average megawatts of technical conservation potential were available to the region to reduce loads by the year 2005 in the high-demand forecast. Using a basis for conservation similar to that used in the 1986 plan, but extending the forecast to 2010 and using updated estimates of economic growth in the region, the technical conservation potential would be on the order of 5,200 average megawatts in the year 2010. Most of this change is due to new estimates of conservation from commercial buildings.

However, significant actions taken over the last few years by various jurisdictions in the region, and in some cases by the federal government, have already set in motion a number of mechanisms that will acquire a large portion of this conservation resource over the next 20 years. For example, the states of Oregon and Washington passed building codes that will, as construction occurs over time, capture part of the conservation resource identified in the 1986 plan. While the Council believes that more aggressive code enforcement is needed to secure these savings, the conservation

potential captured by these new codes shows up as lower use in new buildings in the 1989 supplement forecast.

A similar situation occurs with residential appliances. The federal government passed minimum appliance efficiency standards that will make many residential appliances more efficient than expected in 1986. Primarily as a direct result of these codes, partially as a consequence of updated forecasting models and estimates, and partially as a result of retrofitting that has occurred in the last two years, the total technical potential conservation in this section is about 2,900 average megawatts.³

Table 3-1 presents the average megawatts of conservation and average levelized costs⁴ for all the conservation resources estimated in the 1986 Power Plan and the supplement. Table 3-1 also shows the average megawatts that would have been used in the supplement if the preconservation consumption estimates remained the same as those used in the 1986 plan. These resource estimates are based on the high-demand forecast. In lower-demand forecasts, less conservation is available from many sectors, because the economy is not growing as rapidly, and thus, there are fewer new

houses, businesses and appliances that can supply conservation.

Clearly, the region has taken action since the last plan to help secure conservation resources. About two-thirds of the difference between the current supplement estimates and those that would have been estimated using preconservation consumption from the 1986 plan (over 1,540 average megawatts of technical potential), is due to new commercial building codes and appliance efficiency standards. Some retrofitting activity has also contributed to this difference in estimates. All of the standards were adopted since 1985, when the estimates for the 1986 plan were made.

The remaining one-third of the difference since 1986 is due to computer modeling changes and better information. The estimate of the conservation resource in this supplement assumes that new building codes and appliance standards will continue to be implemented over the planning period. This implies that there is less of the conservation resource left to acquire, because it will be secured through fairly stable mechanisms—building and appliance codes. Energy savings from new codes appear as reduced use in the electrical load forecasts described in the previous chapter.

3./ This value is technical potential in the high forecast and has not been increased to reflect conservation's benefits of avoiding line losses when compared to generating resources, nor decreased to reflect anticipated market penetration rates.

4./ Average levelized costs refers to the total costs of the resource over its lifetime converted to a stream of equal annual payments. This allows resources—both conservation and generating—to be compared on an equitable basis.

Table 3-1
 Comparison of Conservation Savings and Costs^a
 High-Demand Forecast, Technical Potential

	1989 SUPPLEMENT		1989 SUPPLEMENT WITH 1986 PLAN PRE-CONSERVATION USE	1986 POWER PLAN	
	AVERAGE MEGAWATTS (in 2010)	LEVELIZED COST (1988 \$) (cents/kWh)	AVERAGE MEGAWATTS (in 2010)	AVERAGE MEGAWATTS (in 2010)	LEVELIZED COST (1988 \$) (cents/kWh)
<u>Commercial Sector</u>					
Existing buildings	625	2.5	815	780	2.7
New buildings	555	2.2	1,050	515	2.4
Waste-water treatment	15	2.5	15	15	2.5
<u>Residential Sector</u>					
Space Heating:					
Existing single-family	150	3.9	180	385	avg. = 3.5
Existing multifamily	50	4.1	110	115	avg. = 3.5
New single-family	355	3.1	960	770	avg. = 3.6
New multifamily	40	2.4	145	90	avg. = 3.6
New manufactured houses	210	2.2	255	90	avg. = 3.6
Water Heating	385	2.0	530	515	2.2
Refrigerators	110	1.2	335	300	avg. = 1.0
Freezers	35	1.3	160	110	avg. = 1.0
<u>Industrial Sector</u>	280	2.1	500	500	3.7
<u>Irrigation Sector</u>	90	1.9	145	145	2.2
TOTAL	2,900	2.4	5,200	4,330	

^a Average megawatt savings need to be increased to reflect transmission and distribution line-loss savings before comparing to generating resources. Average levelized costs have had the costs increased for administrative costs and adjusted downward for transmission and distribution savings; and the savings used in the average levelized cost calculation have had transmission and distribution line-loss savings incorporated.

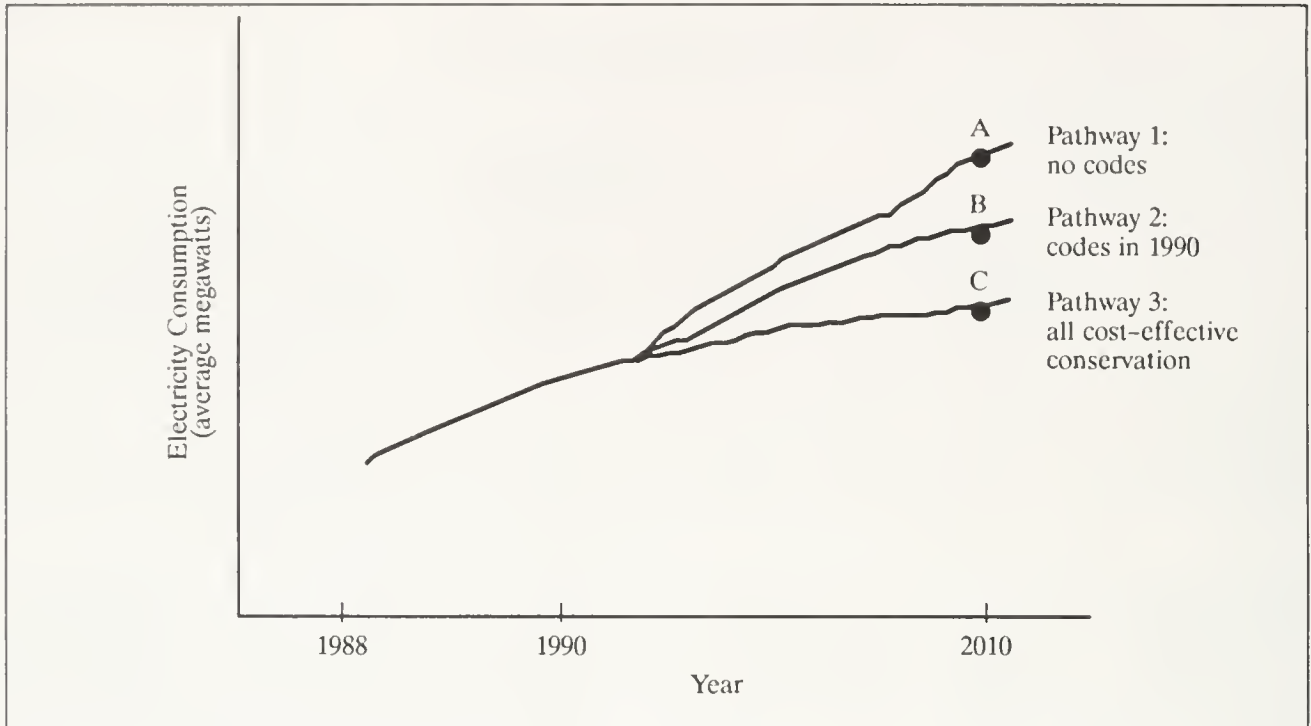


Figure 3-1
The Effect on Loads and Conservation Resources
of Building and Appliance Codes

Legislation that mandates conservation reduces the forecast of electric loads, which, in turn, automatically reduces the amount of conservation potential remaining to be secured. Figure 3-1 depicts the effect of adopting conservation codes and standards on forecast loads and conservation resources. Forecast loads that do not take into account building and appliance codes result in the highest energy consumption over the 20-year horizon, along "Pathway A." "Pathway C" represents electricity loads if all new houses and appliances were to install all the cost-effective conservation available. Once building codes and appliance standards are adopted, each new building or appliance is mandated to be more efficient. This results in an intermediate load forecast, because each new unit will consume less electricity than in Pathway A. But there are still cost-effective conservation measures not included in all of the codes and stan-

dards and many end uses for which there are no codes or standards. This intermediate step is depicted as Pathway B in Figure 3-1. The difference between Pathway A and Pathway B is the conservation secured through the codes and standards. The difference between B and C is the remaining conservation potential that still needs to be secured. This conservation remains a significant and cost-effective resource for the region to acquire.

This chapter summarizes the Council's estimates of conservation resources available to the region. The narrative is based on calculations from the Council's high demand forecast, but similar calculations were done for the low, medium-low, medium and medium-high forecasts. More detailed descriptions of the conservation analysis for the high-demand forecast can be found in Volume II, Chapter 3.

Supply Curves

A supply curve is an economic tool used to depict the amount of a product or resource available across a range of prices. Conservation supply curves represent the number of average megawatts that can be conserved, and made available for other uses, at various costs.

The supply curves used in this plan do not distinguish between conservation that results from specific programs and conservation that results from rising prices of electricity. The perspective in this analysis is regional. Regardless of whether the consumer or the utility invests in a conservation measure, the region is purchasing savings at a particular price, and the conservation resource is secured. Who pays for a conservation resource can make a difference in utility rates, but does not make a difference in the total amount of money spent on the resource.

Conservation supply curves essentially represent the relationship between the conservation measure's cost and the electricity savings the measure is expected to produce. Each measure's savings and cost are used to derive a levelized cost, in terms of cents per kilowatt-hour, for that measure. The levelized costs used to generate the supply curves are based on the capital, financing, operating and maintenance expenditures incurred over the lifetime of the conservation measure. To ensure consistency between the conservation supply curves and the system models,⁵ the same capital recovery factors are used in the levelized cost calculation that were used in the system models. This means that the tax treatments, rate requirements and other financial considerations specific to the developer of the resource are accounted for in the levelized cost of the conservation resource.

Conservation Programs for Resource Portfolio Analysis

Once supply curves are generated for each end use and sector, or by sector alone, the amount of conservation included in the resource portfolio analysis is established by finding the point on the supply curve at which the levelized cost of the last measure is equal to or just slightly less than the avoided cost.⁶ Because the characteristics of conservation resources vary with the resource being developed, the avoided cost also varies. The avoided cost represents the resource or resources that the region is likely to acquire in the long term to meet load growth.

The Council has determined that the avoided cost is 5.5 cents per kilowatt-

hour for "discretionary" conservation resources, or conservation resources that can be scheduled to meet load. Discretionary resources are those that do not need to be fully developed during the current surplus. This category includes conservation from existing buildings—both commercial and residential weatherization retrofit programs.

The 5.5 cents per kilowatt-hour avoided cost also applies to conservation resources that grow automatically with economic development, but are not expected to be developed until the region is no longer in a surplus condition. Savings from refrigerators and freezers beyond the level of new federal standards, but not anticipated to be introduced until 1995, fall into this category.

The avoided cost is between 4.4 and 4.9 cents per kilowatt-hour for conservation resources that grow with loads, have lifetimes longer than the duration of the surplus, and must be acquired today to prevent losing their savings forever. This value is derived from the cost of the package of resources that the conservation displaces. The avoided costs for these resources will increase over time, as the need for new resources nears. Savings from the model conservation standards in new residential and commercial buildings epitomize this type of conservation resource, often called a "lost-opportunity" or "non-discretionary" resource.

The "technical conservation potential" is the amount of conservation available at less than the avoided cost. This technical conservation potential is reduced in the portfolio to reflect the portion of the conservation resource that is considered

to be not achievable. "Achievable conservation" is the net savings the Council anticipates after taking into account factors such as program design, consumer resistance and potential technical problems. The Council believes that the wide assortment of incentives and regulatory measures the Act makes available can persuade the region's electricity consumers to install a large percent of the technically available conservation. As a consequence, the proportion of technical potential considered achievable in this plan varies from 50 percent to 90 percent, depending on the particular end use. In addition, acquisition of the savings from a discretionary conservation resource in the portfolio is limited by how fast a program can become operational.

Achievable savings used in the portfolio are also adjusted to reflect the line-loss savings⁷ resulting from conservation, so they can be compared to generating resources. Finally, conservation costs are increased to reflect program administration costs and decreased to reflect distribution cost reductions and the 10-percent benefit given conservation under the Act. Each conservation program is evaluated in terms of its compatibility with the existing power system and is compared to the cost and energy production characteristics of other electrical energy resources. To assess compatibility, and ultimately the cost-effectiveness of the conservation programs, the Council used both the Integrated System for Analysis of Acquisitions Model and the System Analysis Model. These models serve as a final screen to determine whether the conservation resource is regionally cost-effective.

5./ The system models are the Integrated System for Analysis of Acquisitions and the System Analysis Model.

6./ Avoided cost is used to determine the value of a resource by comparing it to the cost of another resource or set of resources that would otherwise have to be developed if the resource being evaluated were not acquired.

7./ On the order of 7 percent to 10 percent of the electricity generated can be lost during transmission and distribution. With conservation there is no such line loss.

The Integrated System for Analysis of Acquisitions Model determines how much conservation is needed in each of the Council's forecasts. The conservation that the model secures in any one year depends on how fast a program can become operational, and on the ultimate amount of cost-effective conservation available. If the region is surplus for a long time, but a conservation program is already operating, the speed at which the program can be cut back and the minimum viable level at which that program can be maintained are also important in determining available conservation. The minimum viable level of the program, if above zero, determines the amount of savings that would accrue, even though the region might want to delay purchase of the resource during the surplus period.

The following sections describe the technical conservation estimates in various sectors from the high-demand forecast. These technical estimates have not been adjusted to account for transmission savings associated with conservation. However, the average levelized costs for the conservation estimates do reflect an increase in costs from administration expenses and adjustments in costs and savings from transmission and distribution effects.

Residential Sector Results

In 1987, the region's residential sector consumed 5,380 average megawatts of electricity—about 33 percent of the region's total electrical consumption. Space heating is by far the largest single category of electricity consumption in the residential sector; water heating is second.

More is known about end uses in the residential sector than in any other electricity-consuming sector. End uses described in the residential conservation assessment include space heating in existing and new residences, water heating, re-

frigerators and freezers. The supplement identifies about 1,325 average megawatts of technical potential and 1,030 average megawatts of achievable conservation in the residential sector. About 60 percent of this resource is available from reducing the electricity required to heat homes.

Space Heating Conservation in Existing Buildings

Savings from space heating in existing residences can be achieved by improving a house's insulation level, adding storm windows and reducing air leakage. Figure 3-2 shows the estimated space heating savings available from existing residences at various conservation measure costs. The technical potential for conservation from existing electrically heated homes that survive to 2010 is approximately 200 average megawatts. No single measure included in this estimate exceeds 5.5 cents per kilowatt-hour. About 48 percent of this resource is in the public utilities' service territory, and 52 percent is in the investor-owned utilities' service territory. The Council estimates that up to 85 percent (170 average megawatts) of these savings are achievable. The average cost of insulating and weatherizing existing residences is estimated to be 4.0 cents per kilowatt-hour. This cost reflects reduced savings, because residents are expected to turn thermostats up and open more rooms in their house after weatherization. As described above, the average levelized cost also includes adjustments for transmission and distribution savings and administrative costs.

The estimates of the cost of conservation available from space heating in existing houses are based primarily on the costs of weatherization measures reported by current utility programs. The savings-per-house estimates are based on pre-conservation use that reflects regional average conditions in the Council's de-

mand forecast. Use after all measures have been installed reflects the assumption that people will be more likely to turn thermostats up and heat the entire house after their homes have been weatherized. This is consistent with the Council's forecasting model. Both the costs and savings used by the Council to derive the conservation potential from weatherization correlate well with utility experience.

In general, the Council found regionally cost-effective levels of residential weatherization are higher than the levels currently installed by most utility programs. The Council believes that the full cost-effective level of a particular conservation measure should be installed the first time a house is weatherized so that individual weatherization measures do not become lost-opportunity resources. Should a weatherization program only install part of a measure—insulation, for example—it may not be possible to return to the house and install the remaining insulation that would have been cost-effective. This is primarily a consequence of fixed overhead costs associated with adding any level of a given measure.

The resource represented by residential weatherization is discretionary and ideally should not be acquired until the current surplus nears an end. In the 1986 plan, the Council recognized that residential weatherization programs need to continue at a minimum level of activity so that they can be accelerated easily and economically when they are needed. This minimum viable level may be a program to target renter and low-income households specifically, since conservation acquisition capability needs to be developed in these components of the residential sector. Even in these subsectors, it is important not to create lost conservation opportunities when a house is weatherized.

For this reason, the Council recommends that any house weatherized should be insulated to the full cost-effective level of each measure, and records

should be maintained on measures that are cost-effective but not taken. The issue of the level of action that needs to be

taken in weatherization programs may be addressed by the Council in the near future.

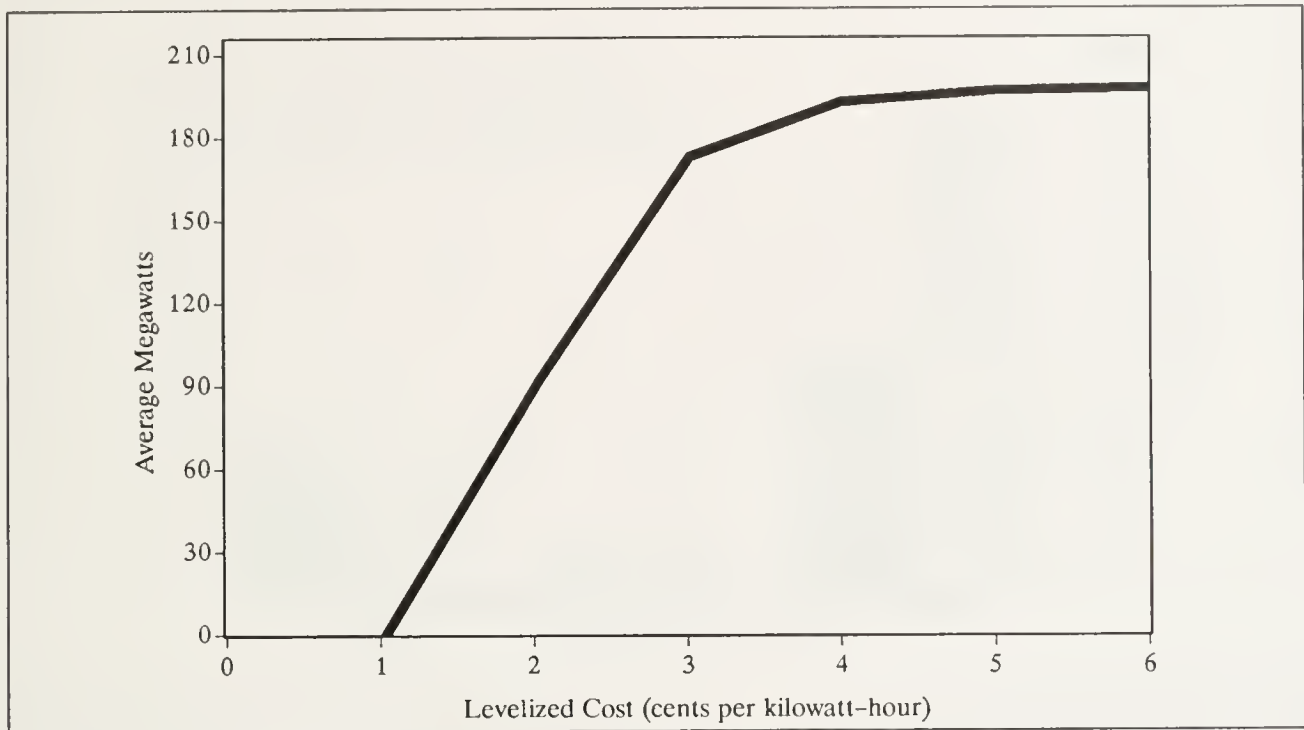


Figure 3-2
Technical Conservation Potential from Space Heating Measures
in Existing Residences

Space Heating Conservation in New Residential Buildings

The Act directs the Council to establish model conservation standards for new electrically heated residential buildings and new commercial buildings. These standards must be designed to secure all savings that are cost-effective for the region. In addition, they must be economically feasible for consumers, taking into account financial assistance made available under the Act.

These model conservation standards represent a significant opportunity to secure a resource that could otherwise be

lost forever to the region. Since most residential and commercial buildings constructed today are likely to last considerably longer than the current surplus of electricity, all cost-effective conservation should be captured at the time the buildings are constructed. Where such cost-effective measures are not installed at the time of construction, it can be prohibitively expensive, if not structurally impossible, to add the measures later.

Since the 1986 Power Plan, the states of Washington and Oregon have taken significant action to improve building codes for new residential construction. At the time this supplement was adopted, these

codes captured about 48 percent of the cost-effective conservation resource available from new single- and multifamily houses.⁸ Figure 3-3 shows how large the resource for new single- and multifamily houses would have been if the 1986 codes had not been adopted, and how much of the resource remains beyond the 1986 codes. In addition, 40 jurisdictions in Washington, Idaho and Montana have adopted more stringent local codes that meet the level of the model conservation standards, which contain all cost-effective and commercially available conservation measures. Since these codes are already adopted

8./ The 1986 revisions to the Oregon State Energy Code required more efficient windows beginning January 1, 1989. Prior Council analyses did not include the savings attributable to this requirement.

and are reflected as proportional reductions in the Council's load forecasts, only the potential of going beyond Oregon

and Washington codes to the level of the model conservation standards them-

selves, is included in the conservation estimate shown in this section.

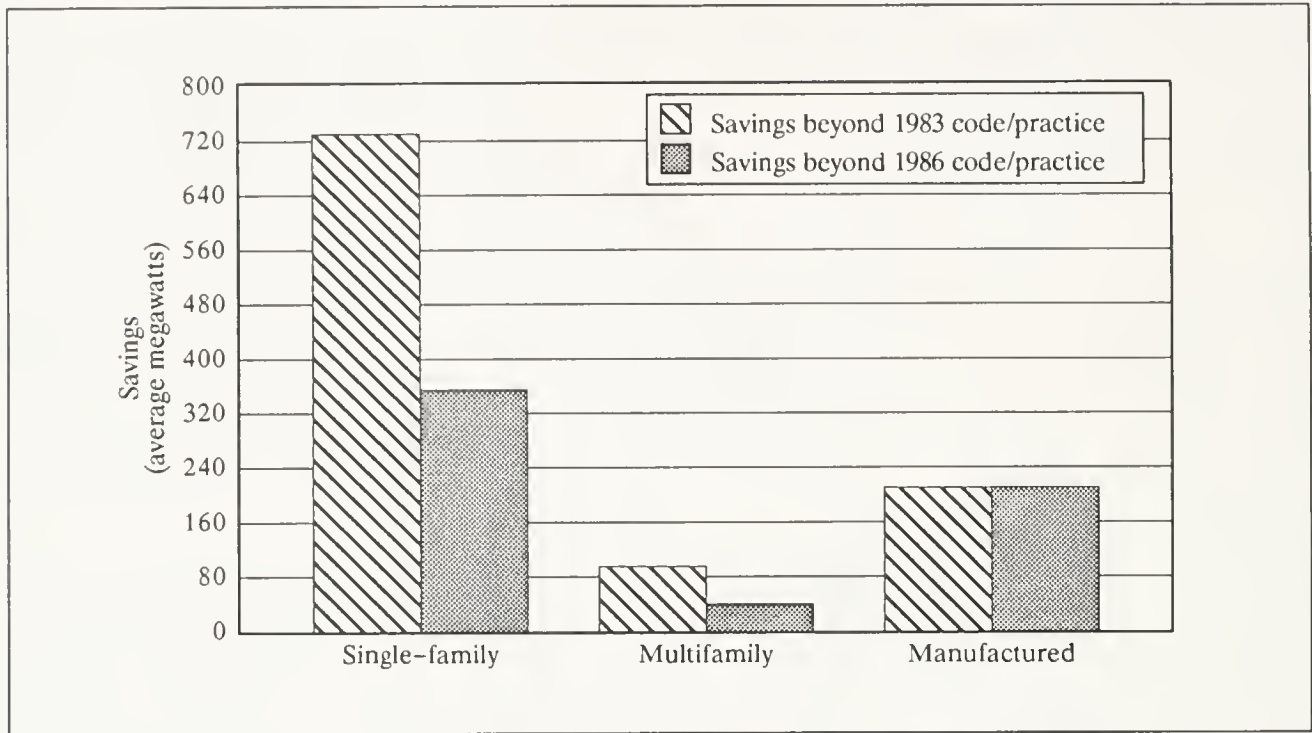


Figure 3-3
Comparison of Conservation Savings from 1983 Practice, Before Adoption of 1986 Oregon and Washington Building Codes and After Adoption

Figure 3-4 shows the technical space heating savings available from new residences at various costs, taking into account savings already captured by the 1986 codes. New single-family and multifamily houses represent approximately 395 average megawatts of technical potential beyond current building codes. Savings from single-family and multifamily houses represented 825 average megawatts prior to the update of Oregon and Washington codes in 1986. Manufactured houses represent approximately

210 average megawatts of technical potential beyond 1986 building practice. About 57 percent of the resource from single-family houses, 33 percent from multifamily and 47 percent from manufactured housing is available in the public utilities' service territories. The remaining resource is in the investor-owned utilities' areas.

The Council's plan calls for developing the following average megawatts of the technical potential: 335 for single-family

homes, 35 for multifamily homes and 105 for manufactured homes. Achievable savings result from building 85 percent of new single-family and multifamily houses, and 50 percent of newly purchased manufactured homes to the level of the model conservation standards starting in 1991.⁹ The average cost of the conservation resource from new residences is about 3.1 cents per kilowatt-hour, including administrative costs and adjustments for transmission and distribution.

9./ Achievable savings phase in over time between 1989 and 1990.

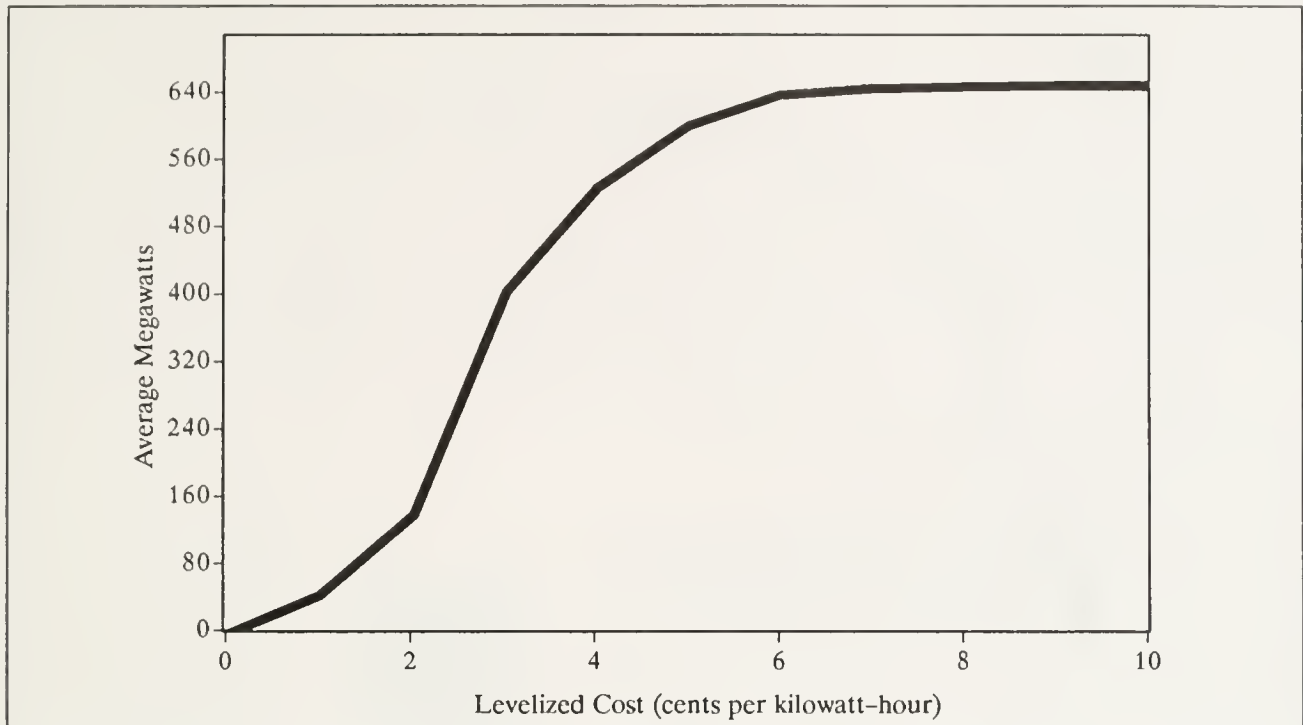


Figure 3-4
*Technical Conservation Potential from Space Heating Measures
 Beyond 1986 Codes/Practice in New Residences*

Estimates of available conservation from single- and multifamily houses are based on the energy savings expected from the model conservation standards adopted by the Council in the 1983 Power Plan and amended in December 1985 and March 1987. The primary change resulting from the 1985 and 1987 amendments was to introduce a high degree of flexibility that allows governments and utilities to implement the standards based on the unique circumstances in their jurisdictions. Although the Council still believes energy codes are the most effective means for securing savings from new buildings, it is emphasizing utility marketing and incentive programs to gain the energy savings from the model conservation standards for the next several years, rather than relying entirely on governmental regulatory authority. These programs will provide regionwide experience with improved techniques for

constructing energy-efficient buildings.

The conservation potential estimated to be available from improvements in the energy efficiency of new residential buildings was based on the most recent information available. The Council used costs reported in the Residential Standards Demonstration Program (RSDP), a regionwide demonstration program to build energy-efficient new homes, and also used experience from areas in the region that have adopted energy-efficient building codes. Even though RSDP data have statistical limitations, the Council is encouraged by the fact that costs reported by the majority of builders participating in the program were consistent with the Council's 1983 cost estimates. For manufactured homes, the Council relied on costs for improving energy efficiency from work done for the Manufactured Housing In-

stitute. Space heating savings from installing conservation measures are estimated using a thermal simulation computer model, called SUNDAY. Significant amounts of monitored space heating data have become available over the last few years on a large sample of houses. SUNDAY has been able to predict space heating consumption quite well over a wide range of housing types and insulation levels.

Water Heating Conservation

The energy used to heat water is the second largest end use of electricity in the residential sector. Figure 3-5 illustrates the potential for improving the efficiency of residential water heating at various costs. These savings accrue from better-insulated water heaters, pipe wraps and more efficient appliances that use hot water (e.g., clotheswashers and dishwashers).

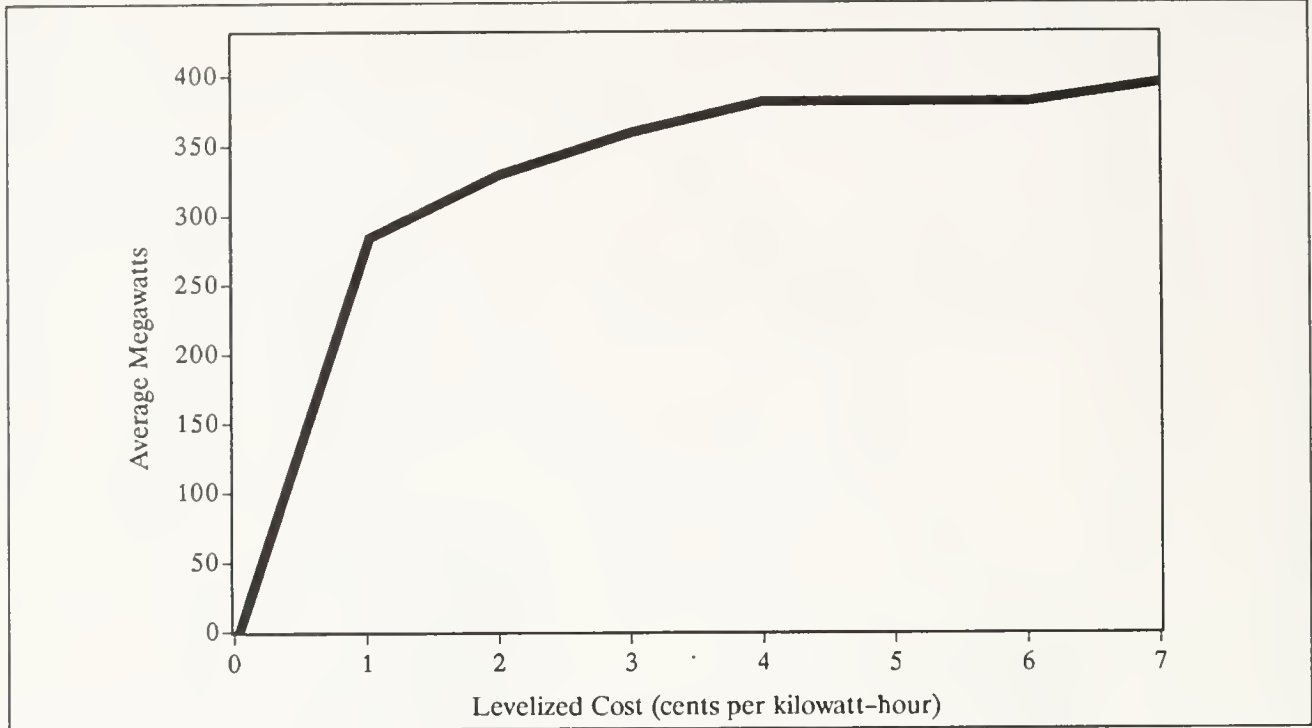


Figure 3-5
*Technical Conservation Potential from Residential
 Water Heating Measures*

The cost-effective technical potential identified by the Council for electric water heaters is about 385 average megawatts. About 44 percent of this potential is in the public utilities' service territory, and 56 percent is in the investor-owned utilities' service territory. The achievable portion of this potential is about 300 average megawatts. The average cost of improving the efficiency of electric water heaters is 1.9 cents per kilowatt-hour, including administrative costs and transmission and distribution adjustments. These savings represent the savings potential of going beyond recent federal legislation that requires minimum efficiency levels for water heaters starting in 1990. The federal standard approximates existing Oregon and Washington water heater standards.

The Council's assessment of the conservation available from improved residential water heating efficiency is based on

cost and savings data collected by utilities, Bonneville and various research organizations. Many measures are highly cost-effective, producing the low average cost of the Council's recommended water heating measures. Two items—heat pump water heaters and solar water heaters—were not cost-effective to the region, under average conditions. If a household uses significantly more than average amounts of electricity for heating water, solar and heat pump water heaters approach the cost-effectiveness threshold. However, savings from heat pump and solar water heaters are not included in the plan as cost-effective water heating conservation technologies.

Conservation in Other Residential Appliances

Approximately a quarter of the electricity currently consumed in the residential sector is used to operate

refrigerators, freezers, stoves and lights. The Council's conservation assessment is based on savings from refrigerators and freezers only.

The Council has included 135 average megawatts in its estimates of technical conservation from refrigerators and freezers, which is slightly less than the amount that could technically be accomplished for measures costing less than 5.5 cents per kilowatt-hour as described below. About 41 percent of this resource is in the public utilities' service territory, and 59 percent is in the investor-owned utilities' service territory. Achievable potential is 120 average megawatts or 90 percent of the technical potential. These savings are based on the number of new refrigerators and freezers estimated to be purchased between 1995 and 2010. At an average cost of about 1.2 cents per kilowatt-hour, the savings from new refrigerators and freezers are among the

most cost-effective conservation resources available to the region.

The savings identified by the Council are based on cost-effective efficiency improvements that go beyond recent federal legislation. The National Appliance Energy Conservation Act was passed by Congress and signed by the President in early 1987. It sets an initial maximum energy consumption level for refrigerators and freezers (as well as other home

appliances) that becomes effective for any unit sold in or after 1990. The federal law also requires a review of these initial standards for refrigerators and freezers in 1990, which could lead to more stringent standards in future years. This initial review is in draft form, and the U.S. Department of Energy should take action over the next year. The results of the federal review will be incorporated in future power plans. The Council's forecast of electricity demand has already in-

corporated the use implied by the current federal 1990 standard, which has become the base case against which further efficiency improvements are measured. Figure 3-6 indicates how much conservation would have been available from refrigerators and freezers if the federal standards had not been enacted. These are compared to savings estimated in this section that go beyond the standards.

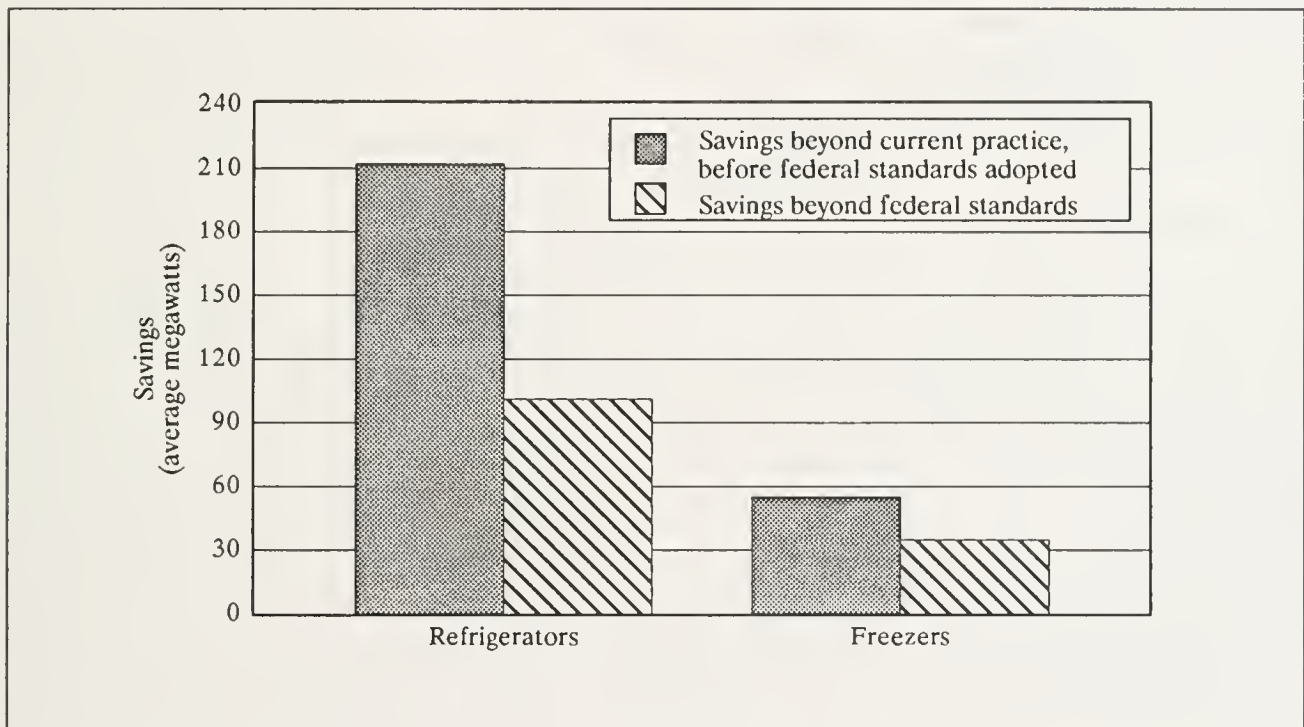


Figure 3-6
Comparison of Savings Before and After
Adoption of Federal Appliance Standards

The Council's current analysis shows that cost-effective efficiency improvements beyond the 1990 federal standard are achievable. These further savings reflect the impact of improving the federal appliance standards during the U.S. De-

partment of Energy's review in 1990. Alternatively, the savings could be secured in this region if the legislatures of the Northwest states were to adopt more stringent levels into law and apply to the

Department of Energy for an exemption from the federal standard. The estimated conservation resource is modeled as revised appliance standards that become effective in 1995.

The level of the estimated revised standard is equivalent to standards set by California before the federal legislation was passed, which would have become effective in that state in 1992.¹⁰

The current estimates of costs and energy savings for efficiency improvements are based on work done for Bonneville by the American Council for an Energy Efficient Economy. This analysis in turn was based on updated information from the U.S. Department of Energy and from hearings on standards before the California Energy Commission. Based on these data, the Council has concluded that improvements to refrigerator and freezer efficiency beyond the federal standard are cost-effective for the Northwest.

Commercial Sector Results

The commercial sector consumed approximately 22 percent of the region's total firm energy sales in 1987, or about 3,479 average megawatts. Space heating, space cooling and lighting dominate this sector's energy consumption. Office buildings and retail stores consume almost 50 percent of the electricity used in the commercial sector.

The commercial sector is made up of diverse buildings that use electricity in many ways. The conservation potential in this sector is based on the electricity use in conventional commercial buildings, such as offices and schools, as well as from less well-known sources, such as pumping in municipal waste-water treatment plants. This sector includes savings from both privately and publicly owned buildings.

The sector's diversity, along with the lack of good data, do not allow the estimates of conservation potential to have the precision that is possible in the residential sector. For example, it is possible

that the computer modeling used to derive the commercial estimates omitted some cost-effective measures. Further investigation into regional projects, such as Bonneville's Energy Edge program, and investigation into the general applicability of additional conservation from lighting improvements, as should be demonstrated through the Seattle Lighting Demonstration Facility, may increase the cost-effective potential in new commercial buildings. For new buildings alone, revisiting this modeling could add another 300 average megawatts to savings estimates in the high-demand forecast.

Further development of the savings estimates from new commercial buildings, along with refining the commercial model conservation standards, is part of the work planned over the next six months. In addition, more work needs to be done on defining the portion of existing commercial savings that could become lost opportunities unless secured now. Projects are currently under way in the region that will enable the Council to address these questions to better evaluate the conservation potential in this sector. While there is uncertainty in the exact amount of conservation available from new commercial buildings, all estimates indicate that the resource is significant, and much of it is a potential lost-opportunity resource. Consequently, programs should focus immediately on the most efficient way to secure this resource.

Figure 3-7 shows the amount of technical conservation potential available from the commercial sector at various costs in existing and new commercial buildings and waste-water treatment facilities. In the high-demand forecast, the Council estimates 625 average megawatts of technical conservation potential in exist-

ing commercial buildings, 555 average megawatts from new commercial buildings and 15 average megawatts from waste-water treatment plants. About 40 percent of these resources are in the public utilities' service territories, and 60 percent are in the investor-owned utilities' service territories.

Achievable conservation from existing commercial buildings is estimated to be 530 average megawatts, available at an average cost of 2.5 cents per kilowatt-hour. This includes an estimate of administrative costs and adjustments for transmission and distribution. Achievable savings from new commercial buildings are estimated to be 470 average megawatts, available at an average cost of about 2.5 cents per kilowatt-hour.

The Council's assessment of cost-effective efficiency improvements for existing and new commercial buildings starts with engineering estimates from 10 prototype commercial buildings. The prototype work is from a contract sponsored by Bonneville. This effort identified the costs and savings from conservation measures that were deemed commercially available and acceptable to most consumers. The prototypes did not estimate the potential savings from redesigning entire building systems to secure further efficiency improvements. Since redesigning systems is an important part of securing conservation in commercial buildings, the prototypes analysis may underestimate savings that can be achieved through a program, such as Bonneville's Energy Smart Design Assistance, that targets conservation action at the design phase of building. The estimates of savings resulting from the prototype work are translated into relative efficiency improvements, which are then incorporated in the forecasting model to

10./ California's 1992 standards were also the efficiency level found cost-effective in the 1986 Power Plan. California's 1992 standard is automatically pre-empted by the federal standard if the Secretary of the Department of Energy acts to review the level of the federal standards by January 1, 1990. However, California's standard becomes effective automatically in 1993, and is automatically waived from federal pre-emption if the Secretary fails to act.

estimate savings consistent with the load forecast.

The savings from new commercial buildings reflect the conservation potential beyond the savings secured by the 1986 Oregon and Washington energy codes. The Council estimates that if these codes are fully enforced, approximately 495 average megawatts of savings, compared to a 1980 building code base, would be se-

cured. These estimated savings, reduced to represent only 85-percent compliance with the code, have already been incorporated into the load forecast as reduced loads. However, there is evidence that compliance with the 1986 Oregon and Washington commercial building codes is far less than even 85 percent. As a consequence, anything the energy system can do to enhance compliance with these

existing codes will prove to be a good buy for the electricity system.

While the Council is committed to investigating the commercial conservation resource further, and actions on this will be taken over the next few months, there are clearly cost-effective conservation resources in the new commercial sector that should be pursued immediately.

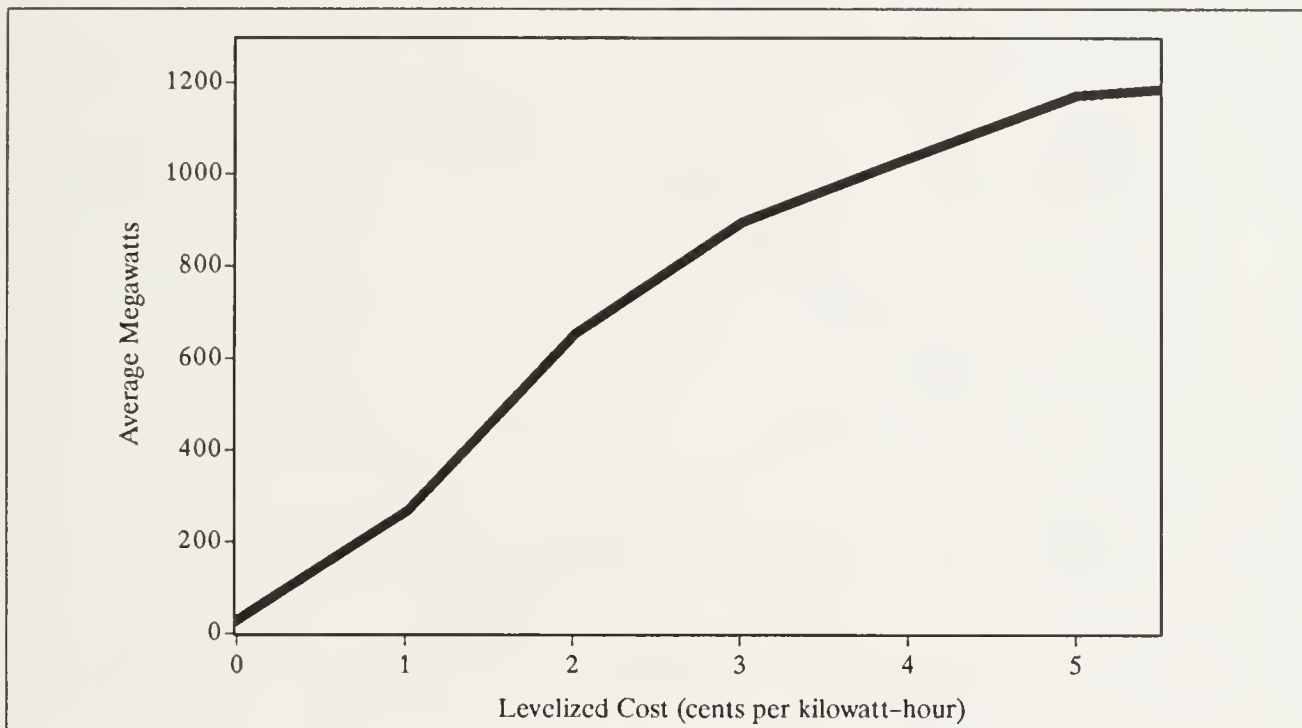


Figure 3-7

Technical Conservation Potential from the Commercial Sector

Industrial Sector Results

In 1987, firm sales to the industrial sector were 6,062 average megawatts, which was about 41 percent of firm regional consumption. About 37 percent of the total industrial demand for electricity was consumed by the direct service industries. These are energy-intensive industries, mainly aluminum and other primary metals and chemical producers,

that purchase electricity directly from the Bonneville Power Administration. Other large industrial consumers are lumber and wood products, pulp and paper, chemicals and food processing.

The Council assumes 260 average megawatts as the technical and achievable conservation potential from the non-direct service industries and an additional 20 average megawatts from the direct

service industries.¹¹ About 47 percent of this resource is available from public utilities' service territories, and about 53 percent is from the investor-owned utilities' service territories. These are the savings that plant managers said could and would be secured for given prices, up to 5.5 cents per kilowatt-hour. These savings are based on existing industrial facilities and do not reflect savings from

11./ Savings from the aluminum industry conservation/modernization program for direct service industries have already been incorporated as a reduction in the load forecast.

new facilities due to the inherent problems with defining a base line for new industrial facilities.

Bonneville recently completed a report that identified over 400 megawatts of lost-opportunity measures in the industrial sector over the next 20 years. Con-

siderable analysis of this estimate is required to determine whether the 260 megawatts identified above are included in the new estimates of lost-opportunity resources, and whether the measures are realistic given existing configurations in industrial plants. This investigation, as well as upgrading the current estimates

of savings, will be part of the Council's work over the next two years. Industrial sector savings cost an average of about 2.1 cents per kilowatt-hour, including administrative costs and transmission and distribution adjustments. Figure 3-8 depicts the technical conservation potential at various costs.

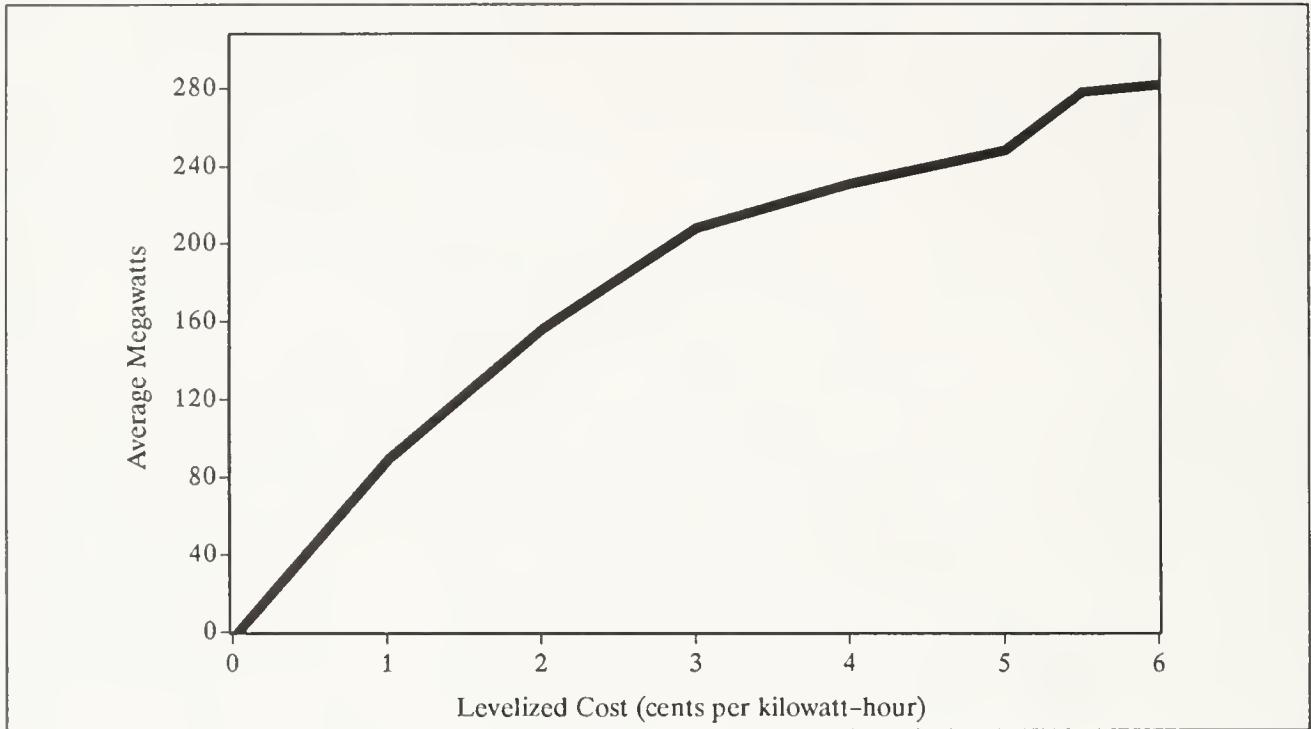


Figure 3-8
Technical Conservation Potential from the Industrial Sector

Assessing the technical and economic potential for industrial conservation presented a more difficult problem than in any other sector. Not only are industrial uses of electricity more diverse than in the commercial sector, but the conservation potential is also more site specific. Moreover, because energy use frequently plays a major role in industrial processes, many industries consider energy-use data proprietary. Estimating conservation potential is not yet possible for new industrial plants, because they are unique in their energy use, and a

“base-case” plant from which to estimate savings has not been established.

In the past, industrial representatives have been skeptical of studies that estimate the potential of industrial conservation based on a “typical plant” within an industry. Such studies extrapolate results from a typical plant analysis to estimate the potential for the whole industry. Industrial representatives argued that typical plants for most industries do not exist. Among other reasons, differences in product lines and the age

of plants do not allow the comparison of individual plants within the same industry. Industrial representatives were concerned that, even though their plants were not like the typical plant used in the analysis, policies and programs affecting them would be based on those analyses.

While preparing the 1986 Power Plan, the Council considered ways to estimate conservation potential in the region's direct service and non-direct service industries that would have the support of industrial representatives. The ap-

proach that received support was a survey asking individual plant managers to estimate conservation potentials in each specific plant. The surveys were coordinated by industry trade associations such as the Northwest Pulp and Paper Association and the Industrial Customers of Northwest Utilities. Data for specific firms were masked to protect proprietary data. Each firm was asked how much conservation would be available at specified prices in each of four areas: 1) motors, 2) motor controls, 3) lighting, and 4) other, a category that depended on the nature of the firm. The firm was also asked to estimate the lifetime of equipment in each of the four categories. Answers from respondents

to the survey were extrapolated to non-respondents in order to capture regional conservation potential. Results from this survey served as the basis for the Council's conservation estimate. Since then, Bonneville implemented the conservation/modernization program for aluminum smelters. The estimated savings from this program have been removed from the estimate of what remains. One hundred percent of the average megawatts identified as achievable by plant managers was considered available to the resource portfolio for the high-demand forecast.

Irrigation Sector Results

In 1987, the region consumed almost 620 average megawatts of electricity for irri-

gating crops, less than 4 percent of the region's total consumption.

Figure 3-9 shows the estimated energy savings available from existing and new irrigation systems at various electricity prices. The technical potential of measures below 5.5 cents per kilowatt-hour is 90 average megawatts. About 60 percent of this resource is in the public utilities' service territories, and 40 percent is in the investor-owned utilities' service territories. The Council's plan calls for developing up to 85 percent of this potential, or 75 average megawatts. These savings are available at an average cost of about 1.9 cents per kilowatt-hour, including administrative costs and transmission and distribution adjustments.

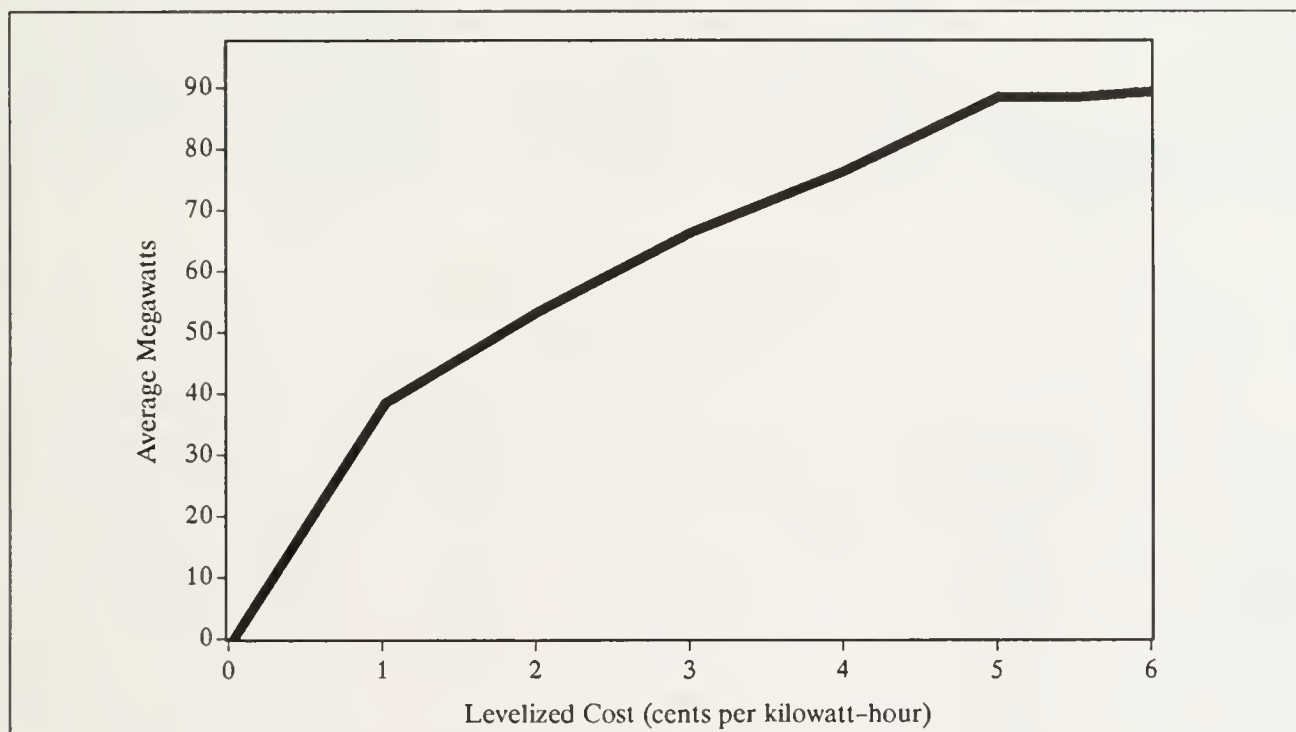


Figure 3-9
Technical Conservation Potential from Irrigated Agriculture

The Council assessed conservation potential for this sector by evaluating more efficient water application systems and water application scheduling improve-

ments for both new and existing acreage. The estimates were based on a computer model that combines engineering and economic principles to derive energy sav-

ings and levelized costs per kilowatt-hour.

Conservation in the Existing Power System

Efficiency improvements to existing generating units as well as the region's transmission and distribution system also represent a source of conservation savings. These savings are described in detail in Chapter 4 of this supplement, "Generating Resources." In addition, Chapter 4 covers savings from voltage reductions on distribution feeders.

Direct Application Renewables

Technologies are available that use renewable energy forms to perform the same tasks as electricity. These energy sources and their functions include wood, solar and geothermal space and water heating, and wind machines used for mechanical drive (such as pumping). These technologies are called "direct application renewables." Their cost-effectiveness is highly site specific, and their environmental impact varies. For

example, the economics of geothermal district heating depend upon the distance between the geothermal resource and its ultimate point of use. The economics of solar space and water heating depend upon (among other things) whether a house has clear access to the sun. Wood heating may be cost-effective if consumers are close to an adequate wood supply and take measures to reduce air pollutants emitted from their stoves.

Although the site-specific economics of these direct application technologies prohibit a general statement regarding their cost-effectiveness to the region, the Council calculated the levelized cost of one technology, solar water heating, in this supplement. These calculations showed that, in general, solar water heating is not yet a cost-effective resource in the Northwest. Based on average conditions, savings from solar water heaters cost about twice than the avoided cost. In a household that uses a lot of hot wa-

ter, or if the cost of the heaters and their installation comes down, conservation from solar water heaters comes within the avoided-cost threshold. As direct application technologies are developed, their costs will likely decline. The Council anticipates that some of these technologies, applied in the right circumstances, will make significant contributions toward offsetting the need for new generating resources during the next 20 years. The Council will accommodate development of direct application resources in subsequent revisions to the power plan.

Planned Conservation--All Sectors

Table 3-2 and Figure 3-10 summarize by sector the projected demand and planned conservation for the Council's high growth forecast. Conservation resources in the Council's plan reduce the projected overall demand for electricity by 8 percent in the year 2010 under the high forecast.

Table 3-2
Summary of Projected Demand and Conservation
in the High Forecast in 2010
(Average Megawatts^a)

SECTOR	DEMAND IN 2010 WITH CURRENT EFFICIENCIES	DEMAND IN 2010 WITH PLAN'S CONSERVATION	DEMAND IN 2010 PERCENT SAVINGS	ACHIEVABLE CONSERVATION INCLUDED IN COUNCIL'S PLAN
Residential	10,380	9,350	10%	1,030
Commercial	7,880	6,890	13%	990
Industrial	10,750	10,470	3%	280
Agricultural	625	550	12%	75
TOTAL ^b	29,635	27,260	8%	2,375

^a Does not include line losses.

^b Excludes the category termed "other," which is a demand of 219 average megawatts.

The actual rate of conservation development between 1989 and 2010 will depend on the level of population growth and economic activity during that period.

Thus, the Council's resource portfolio for its high-growth forecast contains significantly more conservation than for its low-growth forecast. This is because,

with low growth, fewer resources are required, fewer buildings built, fewer appliances bought, and fewer average

megawatts are obtained from new customers. To meet the high-demand forecast, all conservation resources are developed.

In the low forecast, however, less electricity is required to meet projected load growth, and the energy from discretionary conservation programs is not needed.

Programs such as the model conservation standards do continue to supply energy as new buildings are constructed in the low-demand forecast.

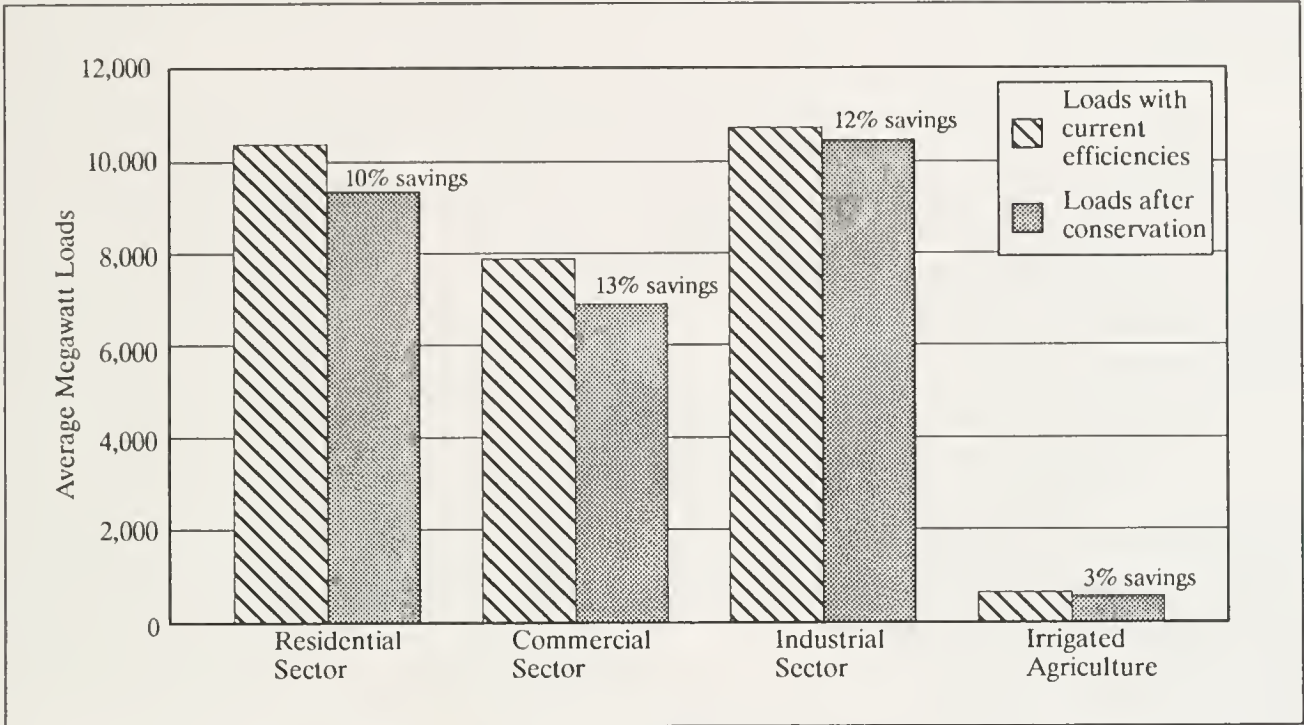


Figure 3-10
 Summary of Projected Loads and Conservation in 2010
 (High-Demand Forecast)

Chapter 4

Generating Resources

The Northwest Power Act requires the Council to prepare a regional power plan that gives priority to cost-effective resources. To determine cost-effectiveness, the Council estimates the costs, availability and other important characteristics of new conservation and generating resources.

Because information on new resources generally improves over time, it is necessary to periodically reassess planning assumptions for new resources to keep the plan current. In December 1987, the Council began its review of several generating resources in light of significant new information, changes in technology, or other factors that may affect planning assumptions in the 1986 Power Plan. Several of these reassessments have been completed and have led to new or revised resource planning assumptions. These are described in this chapter. Other assessments continue and may lead to additional revisions that would be adopted in the next power plan. The status of these continuing assessments is also described in this chapter.

Scope

The Council reviewed selected generating resources and possible improvements to the efficiency of the regional transmission and distribution system. Although such efficiency improvements are actually conservation resources, as defined by the Northwest Power Act, they are treated with generating resources because of their association with the power supply system. The following resources were examined:

Transmission and Distribution Efficiency Improvements

A Bonneville Power Administration study to assess the regionwide potential for transmission and distribution system loss reduction, called for in the 1983 plan, suggests a far greater potential for loss reduction than the 34 average megawatts in the 1986 plan.

Conservation Voltage Regulation

The 1986 plan also called on Bonneville to assess the energy savings potential of improved distribution voltage regulation. This study, now complete, suggests that up to 200 average megawatts could be secured.

Improved Hydropower Coordination

U.S. and Canadian representatives are negotiating possible improvements to the coordinated operation of the Columbia River system. Preliminary reports indicate that several hundred megawatts could be secured through improved coordination.

Hydropower

Better information on regional stream values and proposals for hydropower development is now available. The Council also has designated certain high-value stream reaches as protected from new hydropower development. In addition, improved estimates of new hydropower costs and availability have been adopted.

Fossil Fuel Prices

Substantially lower fossil fuel prices since 1986 affect the relative cost-effectiveness of fossil-fuel based energy generating technologies, particularly those using natural gas. Revised price forecasts for coal, fuel oil and natural gas are adopted in this chapter.

Cogeneration

Improvements in cogeneration technology and the decline in natural gas prices have fueled interest in cogeneration nationwide. Based on a Bonneville study, preliminary estimates of the likely cost and availability of new cogeneration have been prepared.

Combustion Turbines

New combustion turbine designs, offering improved performance, have been introduced. This, plus the decline in natural gas prices, and interest in using combustion turbines to back up nonfirm

hydropower and to generate electricity using gasified coal as the fuel, has elevated the importance of the technology in the Council's planning. Revised assumptions regarding representative cost and performance characteristics of state-of-the-art simple- and combined-cycle combustion turbines are included in this supplement.

Coal-fired Power Plants

Coal-fired power plants are the basis of the long-term marginal—or most expensive—resource costs in the 1986 plan. The costs and performance of such plants were reviewed to ensure that they are current. Representative characteristics listed for both conventional and fluidized-bed coal plant designs were updated for this supplement.

Coal Gasification

Coal gasification technology has been demonstrated in a utility application at the Coolwater Plant in California. In addition, Bonneville has completed a study of the cost and performance of a generic Northwest coal-gasification combined-cycle project. This supplement includes representative cost and performance characteristics of a coal-gasification combined-cycle plant built in phases.

Hanford Generating Project Repowering

The Hanford N-Reactor has been shut down, leaving the Hanford Generating Project (HGP) without a steam supply. The Washington Public Power Supply System has commissioned conceptual studies of ways to repower it. Preliminary estimates of the cost and performance of several options were prepared for the draft supplement. Bonneville has recently completed a more detailed feasibility study of repowering options. Because the information in that study renders obsolete the analysis appearing in the draft supplement, the analysis of repowering options has been removed from this final supplement. The Council

may undertake further analysis of Hanford Generating Project options for the next plan.

Assessing Resource Cost-effectiveness

The Council judges the cost-effectiveness of resources using the following criteria:

- Commercially available technology – The technology to conserve or produce electric power must be commercially available.
- Predictable cost and performance – The technology must be sufficiently demonstrated so that cost and performance characteristics are predictable.
- Competitive cost – The resource must be cost-competitive using available technology.
- Demonstrated resource base – Estimates of the amount of capacity and energy available from a given resource require a confirmed primary energy source (e.g., coal, falling water, wind).
- Institutionally feasible – Development of the resource must not be prohibited by legal, financial, regulatory or other institutional barriers.
- Environmentally acceptable – The resource must be environmentally acceptable and capable of complying with environmental policies, laws and regulations of the federal, state and local governments, and the Council's Columbia River Basin Fish and Wildlife Program.

Resources meeting these criteria are candidates for the resource portfolio of the power plan. The resource portfolio is used to assess resource scheduling requirements and the cost-effectiveness of specific resource acquisition and development proposals. Resources are included in the portfolio only if they are

cost-effective when compared with other available resources. The most expensive resource for this comparison is called the marginal resource. In the Council's plan, coal is the marginal resource. However, only the approximate cost of coal plants is known when assessments of the cost and availability of individual resources are being prepared, so an interim limit of 6 cents per kilowatt-hour is used for the Council's initial review of these resources.

The absence of a specific resource from the portfolio does not mean it is not potentially cost-effective. Resources in the portfolio are those the Council currently expects to be available to meet future needs. When new resources must be secured, it is expected that requests will be issued to solicit any then-available potentially cost-effective resources. Any individual resource meeting the cost-effectiveness test (and other requirements that may be imposed, such as those to ensure compatibility with the system) may be acquired. The resulting resource mix may differ considerably from the current portfolio, in both the type and quantity of resources developed.

The status of generating resources for meeting future needs of the region are shown in Table 4-1. Reasons for excluding resources from the resource portfolio are shown on the right.

Improvements to the Efficiency and Operation of the Existing Regional Power System

Transmission and Distribution Loss Reduction

Regional transmission and distribution system losses comprise about 7.5 percent of regional load, or about 1,300 megawatts for the 1988-89 operating year. Bonneville's system losses amount to only 139 megawatts or about 10 percent of the regional total. The 1986 plan in-

cluded 34 megawatts of savings from improvements in the Bonneville portion of this system. Insufficient information was available to estimate potential savings on the non-Bonneville portion of the region's transmission and distribution system.

Estimates of the cost and availability of potential savings in the 1986 plan were based on specific loss reduction projects identified by Bonneville's Loss Savings Task Force. A recent report by Bonneville's Loss Savings Task Force, plus earlier task force estimates, suggest total firm-energy savings of at least 45 megawatts on the Bonneville system are available at 6 cents per kilowatt-hour or less (Figure 4-1). This represents about 32 percent of Bonneville's system losses for 1988-89.

In response to the 1986 Action Plan, Bonneville prepared an assessment of potential energy savings from upgrading regional transmission and distribution systems other than those operated by Bonneville. Measures considered included upgrading primary distribution feeder voltage, replacing standard transformers with more-efficient designs, and replacing conductors on transmission lines and primary distribution feeders.

In Bonneville's assessment, improving primary distribution feeder voltages proved to be the most cost-effective of the distribution system measures. This upgrade was selected for all distribution feeders to which it would apply—about 75 percent of primary distribution feeder circuit miles in the region. Because new distribution and substation transformers are required to upgrade distribution feeder voltages, the voltage upgrade measure pre-empts individual replacement of substation or distribution transformers. The Bonneville study chose the replacement of transformers and conductors for the balance of the distribution system and for non-Bonneville transmission lines.

Table 4-1
Availability of Generating Resources for the Resource Portfolio

	LAST ASSESSED	AVAILABLE ENERGY		COMMENT ^a
		1986 PLAN (MWa)	W/89 SUPP (MWa)	
Transmission and Distribution Loss Reduction	1986	34	34	Assessment of non-Bonneville systems under way
Conservation Voltage Regulation	--	--	--	Assessment under way
Hydropower Efficiency Improvements	1986	112	112	
Thermal Plant Efficiency Improvements	--	--	--	Insufficient data for assessment
Geothermal	1986	--	--	Unconfirmed resource base
New Hydropower	1988	200	410	
Municipal Solid Waste	1983	--	--	Institutional and environmental uncertainties
Wind	1986	--	--	Not cost competitive
Solar	1986	--	--	Not cost competitive
Wood and Misc. Biomass	1983	--	--	Included in cogeneration estimates
Cogeneration (Biomass & Natural Gas)	1986	190-320	190-320	Reassessment under way
Natural Gas (for backing up nonfirm)	1986	712	712	Cost-effective limit with 1986 gas price forecast, using simple-cycle turbines
Coal	1988	5,425	5,425	Environmental uncertainties
Nuclear (WNP-1 and WNP-3)	1986	--	--	Uncertain ability to finance preservation and completion
New Imports	1986	--	--	Uncertain availability

^a The status or information availability for certain resources has changed since preparation of the draft supplement. The Council intends to reassess these resources for its next plan.

Potential energy savings of about 310 megawatts appear to be available on non-Bonneville systems at costs less than 6 cents a kilowatt-hour (Figure 4-1). This represents about 20 percent of the estimated losses on these systems. Much of this resource (237 megawatts) is estimated to be available at 2 cents a kilowatt-hour, or less. Further refinement of these estimates is required.

The following issues remain to be resolved:

- achievable levels and rates of penetration;

- persistence of savings as circuit loads grow;
- appropriate financial assumptions;
- salvage value of replaced equipment; and
- program administrative costs.

The Council will complete this reassessment for the next plan. Until the reassessment is complete, the Council will continue to use the estimates of potential energy savings from transmission and distribution system efficiency improvements adopted for the 1986 plan.

Conservation Voltage Regulation

Conservation voltage regulation is the process of reducing distribution feeder voltage drop and improving feeder voltage regulation so that the optimal voltage range for appliance¹ operation is achieved at all points along the distribution circuit. Because appliances tend to operate less efficiently at extreme voltages, improved regulation generally improves appliance efficiency and reduces energy consumption.

1./ "Appliance" is used in this discussion in the sense of any device for the use of electricity, including motors, resistance heaters, lights, etc.

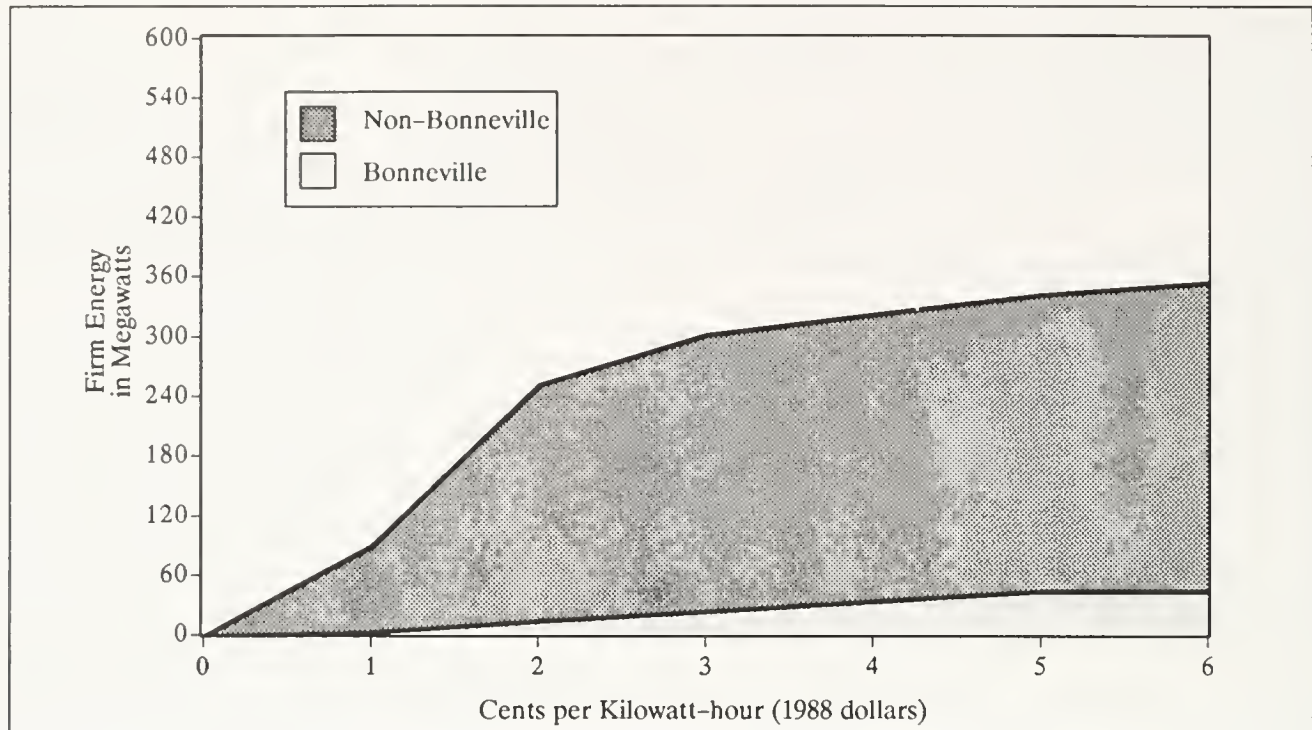


Figure 4-1
Preliminary Estimate of the Availability and Cost of
Transmission and Distribution Efficiency Improvements

While some early studies showed inconclusive benefits, a consensus is emerging that improved voltage regulation can provide both low-cost energy savings and peak load reduction. Several utilities in the region and elsewhere are implementing conservation voltage regulation programs, and California instituted mandatory voltage standards in 1978. California's program is reported to be very successful, with few consumer complaints.

Improved voltage regulation normally involves two steps. First, a loss-reduction program is undertaken on the targeted distribution feeder to reduce voltage drop along the feeder. On shorter or lightly loaded feeders, this step may not be necessary. Second, feeder voltage regulation is adjusted to maintain the

minimum standard voltage at the end of the distribution feeder. Improved voltage regulation equipment may be required to do this. The resulting control range for nominal 120-volt service will typically be the lower half of the national standard voltage control range of 114 to 126 volts.

Bonneville has assessed the cost and availability of energy savings through improved voltage regulation in the Northwest. Estimates of savings versus percent voltage reduction were developed for representative feeders for each end-use sector. Using survey data, regional distribution feeders were categorized into classes requiring specific equipment upgrades and having the potential for specific levels of voltage

reduction. Estimates were then made of the likely range of energy savings and the cost of required upgrades for each feeder class. These estimates were used by the Council in developing the preliminary supply curve in Figure 4-2.

Figure 4-2 indicates a potential region-wide resource of about 200 megawatts at levelized costs of 6 cents or less. Approximately 40 percent of this potential is thought to be on publicly owned utility systems, and 60 percent on the investor-owned utility systems. Most striking is that more than 75 percent of the savings may be available at levelized costs of 1 cent a kilowatt-hour or less, and 50 percent at .5 cents or less. Low-cost savings are associated with feeders where new equipment would not be required.

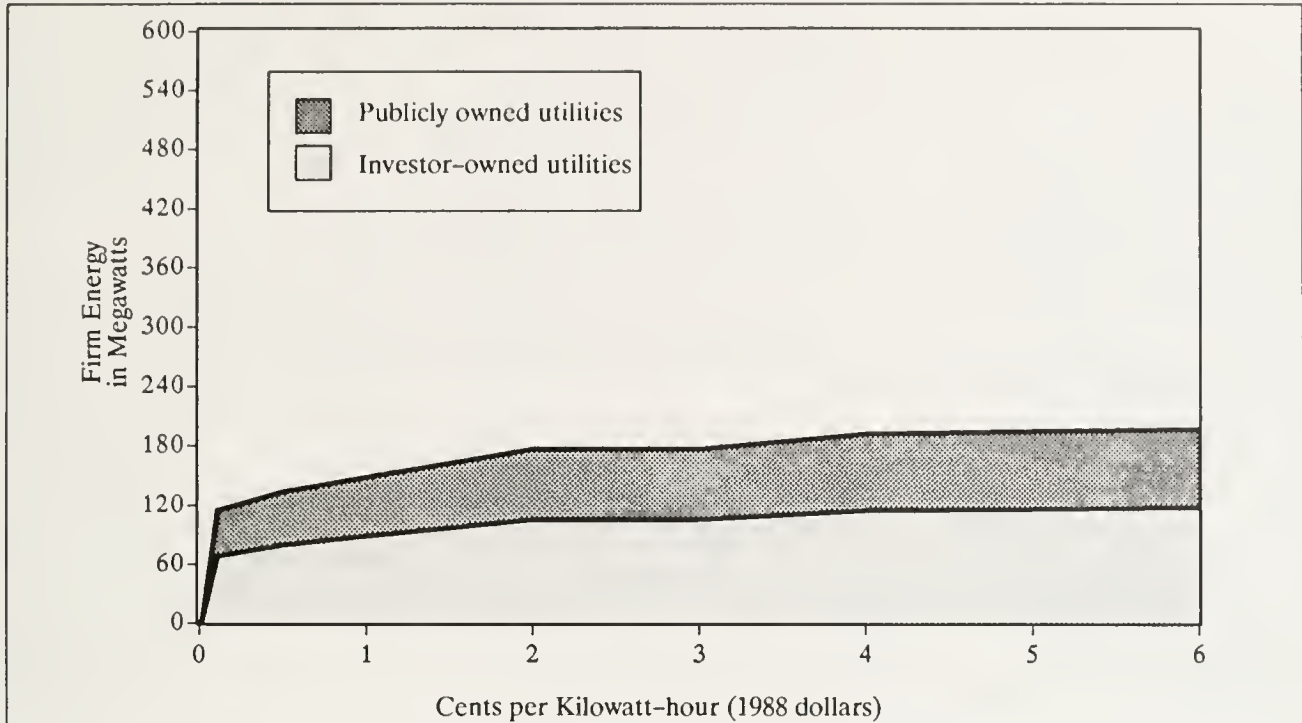


Figure 4-2
Preliminary Estimate of the Availability and Cost
of Improved Voltage Regulation

Further refinement of the assessment of energy savings from improved voltage regulation is required. The following aspects must be clarified:

- achievable levels and rates of penetration;
- possible double counting of transmission and distribution efficiency improvement savings;
- possible double counting of end-use conservation savings;
- reduced value of those savings that offset waste-heat space heating;
- future savings from expansion of the distribution system to meet load growth;
- operation and maintenance costs;
- appropriate financial assumptions;
- program administrative costs; and
- effects on wholesale revenues.

These areas will be further assessed by the Council during the development of the next plan.

Hydropower Efficiency Improvements

The Council estimates 112 megawatts of hydropower efficiency improvements are cost-effective at costs ranging from 0.1 to 1.1 cents per kilowatt-hour. Because of little new information, this resource was not reassessed for this supplement. A small portion of the resource estimated to be available in the 1986 Power Plan may have been secured, somewhat reducing the estimated availability of the resource. This is unlikely to significantly affect the resource portfolio.

Thermal Plant Efficiency Improvements

Because no additional region-specific information regarding thermal plant effi-

ciency improvements surfaced since the 1986 Power Plan, this resource was not assessed for this supplement.

Better Use of the Existing Hydropower System

Electrical resources are planned, and long-term contracts are signed, on the basis of a defined minimum capability of the streamflow and reservoir system—a standard called “critical water.” Critical water is the worst sequence of low water conditions encountered since record keeping began in 1879. The average annual output of the hydropower system, however, exceeds energy from critical water by 33 percent, or approximately 4,100 megawatts—equal to the output of five nuclear plants and enough power to supply four cities the size of Seattle. This excess power is called “nonfirm.” In the 1986 plan, the Council explored ways to turn this nonfirm energy (so-called be-

cause it is not always available) into firm energy, and determined that approximately 700 megawatts of firm energy from this source would be cost effective.

During development of this supplement, the Council looked at the value of also firming an additional 2,300 megawatts of nonfirm. Nonfirm energy is currently sold to direct service industries (mostly aluminum companies), the region's generating utilities and Southwest utilities. While Bonneville's intertie access policy has helped the region secure a better nonfirm energy price, that price is still significantly less than what would have to be charged for energy from most new generating resources. Thus, significant benefits to the region can be secured through strategies to make nonfirm energy more reliable, so it can be used to serve new and existing firm loads. These strategies also appear to be less costly than developing most new generating resources.

Methods to back up the nonfirm energy production of the region's hydropower system include the use of new power plants, improved coordination of the United States and Canadian portions of the Columbia River system, the purchase of energy from existing power plants, increased interruptible loads and other load management techniques. The most cost-effective approach would probably involve some combination of these methods.

Addition of any dispatchable resource (with the possible exceptions of nuclear or geothermal resources) to the region's power system will "firm" nonfirm energy. This is because dispatchable resources generally have variable costs in excess of the value of nonfirm hydropower. Nonfirm hydropower will be used to back down the dispatchable resource whenever it is available. This is current practice in the region. The issue, therefore, is not whether, but how, the region should "firm" nonfirm power (i.e., what new resource type is the most cost-effective

addition to the region's resource portfolio when the need to add generating resources occurs?).

Recent Council studies indicate that it may be cost-effective to add about 3,500 megawatts of combustion turbine capacity to the region's power system before constructing conventional coal plants to serve new load. These plants, operating in conjunction with the nonfirm production of the regional hydropower system, would produce about 3,000 megawatts of firm energy.

Though the operating costs of combustion turbines are higher than those of coal-fired power plants, nonfirm energy is available much of the time to displace (shut down) the combustion turbines. Because of their relatively low capital cost (when compared to coal-fired power plants), and frequent displacement by nonfirm hydropower, adding new combustion turbines would be more cost-effective than building new coal-fired power plants.

Because of the statistical probabilities of nonfirm hydropower availability (see the regional hydro-duration curve in Chapter 5, Figure 5-6) the first combustion turbine units to be added would be displaced frequently. Because these units would operate only infrequently, it would be most cost-effective to use simple-cycle combustion turbines. These units, though only moderately efficient, have low capital costs.

As more units are added, the availability of nonfirm hydropower to displace these plants would decline. (The new units would be positioned further to the right on the hydro-duration curve found in Chapter 5, Figure 5-6.) Because these units would operate more frequently, it would be cost-effective, at some point, to add more-costly, but also more-efficient, combined-cycle combustion turbine plants rather than the less efficient, simple-cycle combustion turbines.

Council studies indicate that combined-cycle plants would become more cost-effective than simple-cycle combustion turbines after about 1,200 megawatts of new simple-cycle combustion turbine capacity (producing about 1,000 megawatts of firm energy) had been added to the system.

As more combined-cycle units are added to the system, the availability of nonfirm hydropower to displace the later additions continues to decline. At some point, it becomes more cost-effective to add new coal plants, with their low-cost fuel, rather than to continue to add combined-cycle plants to the system. Preliminary Council studies indicate that new coal plants become more cost-effective than new combined-cycle plants following addition of about 2,400 megawatts of combined-cycle capacity, producing about 2,000 megawatts of firm energy.

The magnitude of the 2,300-megawatt increment of natural gas-fired resource raises issues regarding the feasibility of securing this resource. Among these are the following:

- the effect of firming nonfirm hydropower on other users of this resource;
- effects on system reliability;
- long-term availability of sufficient natural gas at forecasted prices;
- possible rate swings from periodic use of relatively more expensive resources to back up nonfirm hydropower; and
- environmental effects of operating thermal plants to back up nonfirm hydropower.

Further assessment of these and related issues will be undertaken during the development of the next plan. Until this reassessment is complete, the Council will continue to use the estimate of 700

megawatts of cost-effective firming adopted for the 1986 plan.

New Generation Using Renewable Resources

Geothermal

No geothermal-electric power plants operate in the Northwest. However, the resource assessment in the Council's 1986 plan, based on Bonneville's "Four State Study," indicates that approximately 4,400 megawatts of geothermal-based electric energy might be obtained at a cost less than that of new coal plants. This resource appears to be cost-competitive and uses commercially available and proven technology. But because the suitability of the region's geothermal resource base for power production had not been confirmed, the resource was not included in the resource portfolio of the 1986 plan.

New information confirming that the region's geothermal resources might be suitable for electricity generation was not available for this supplement. However, recent exploration in the Cascades may provide such information. For this reason, the Council plans to reassess the geothermal-electric resource potential for its next plan.

New Hydroelectric Power

The region's existing hydropower projects provide about 29,800 megawatts of capacity and about 12,300 megawatts of firm energy. Most environmentally acceptable large-scale hydropower sites in the region have been developed. Remaining potential includes irrigation, flood control and other non-power water projects that could be retrofit with generating equipment; addition of generating equipment to existing hydropower projects; plus some undeveloped sites that may be suitable for development.

Hydropower is a renewable energy source and is free from toxic emissions. Many proposed projects would produce small increments of power and require relatively short construction lead times, although licensing lead times may be lengthy. Some projects, though, may have profound environmental impacts on streams, surrounding land, and fish and wildlife.

In 1983, the Council reviewed estimates of new hydropower that ranged from 450 average megawatts to as many as 2,377 average megawatts achievable at a levelized cost of 4 cents per kilowatt-hour or less (1980 dollars). The Council included 920 megawatts (firm energy) of cost-effective new hydropower in the 1983 plan. Because there was no need for new resources, hydropower acquisition was limited to a recommendation that Bonneville secure several hydropower options² to test the newly developed "options" concept.

Concerns over the environmental impact of new hydropower, and particularly the potential conflict of new hydropower with the Council's fish and wildlife program, led the Council to seek better information regarding potential hydropower sites. For this purpose, the Pacific Northwest Hydropower Site Database was developed through the joint efforts of the Council, the U.S. Army Corps of Engineers and the Bonneville Power Administration. This data base contains location, cost and performance information on all regional hydropower sites that have been brought before the Federal Energy Regulatory Commission for permitting, licensing or exemption, and sites identified by the Corps of Engineers' National Hydropower Survey. Computer algorithms are available to estimate project capacity, energy production and

costs, where such estimates are not available from project developers.

The need to better understand the non-hydropower values of streams potentially affected by hydropower development led the Council and Bonneville, assisted by federal agencies, states and tribes, to undertake a comprehensive assessment and evaluation of regional river resources. The work addressed anadromous (ocean-migrating) fish, resident (non-ocean-migrating) fish, wildlife, natural features, cultural features, recreation and Indian cultural sites. Approximately 134,000 stream miles were surveyed (approximately 40 percent of the region's total). This inventory did not include streams in areas currently under federal protection (such as wilderness areas) or small headwater streams. Each stream reach is classified as to the presence or absence of anadromous fish, and ranked, using four levels of value, for each of the other resources. The information is maintained by Bonneville and the Council on a computer data base.

Because the Hydropower Site Database and the Hydropower Assessment Study were incomplete in 1986, the Council used a conservative estimate of 200 megawatts of firm energy potentially available from future hydropower development. This represented the portion of firm hydropower in the 1983 plan that could be obtained by development at existing water control structures. The regional surplus precluded the need for any development of hydropower.

The Hydropower Site Database along with the river values assessments, are now available. In addition, the Council has designated protected stream reaches that will assist in maintaining high-value anadromous fish, resident fish and wild-

2./ Options – the purchase of a right to acquire a resource within a particular time on specified terms. Using options, the region can carry out the relatively inexpensive but time consuming design and siting phases of resource development, then forestall expensive construction until the resource is needed.

life resources. Even with improved information and adoption of protected areas, uncertainties remain regarding the cost and availability of new hydropower. If only sites having existing water control structures are developed, as few as 185 average megawatts of firm energy might be available at a cost of 6 cents per kilowatt-hour or less.³ However, if all proposed projects are developed (consis-

tent with protected areas requirements), as many as 900 megawatts of firm energy might be obtained at 6 cents per kilowatt-hour or less. The Council believes that a reasonable estimate of new hydropower potential is 410 average megawatts of energy at 6 cents per kilowatt-hour or less. This "probable" supply curve is shown in Figure 4-3.

Because of the wide cost range the "probable" supply curve of Figure 4-3 was divided into four resource blocks for incorporation into the Council's resource portfolio analysis. Table 4-2 shows key planning characteristics for these blocks. More detail is provided in Volume II, Chapter 4.

Table 4-2
New Hydropower Block Planning Characteristics

	NEW HYDRO 1	NEW HYDRO 2	NEW HYDRO 3	NEW HYDRO 4
Total Capacity	190	290	340	240
Total Average Energy (MWa)	110	130	160	110
Total Firm Energy (MWa)	91	100	130	89
Seasonality	Spring peaking	Spring peaking	Spring peaking	Spring peaking
Siting & Licensing Lead Time (mos)	36	36	36	36
Siting & Licensing Shelf Life (yrs)	4	4	4	4
Construction Lead Time (mos)	36	36	36	36
Siting & Licensing Cost (\$/kW)	\$74	\$93	\$130	\$160
Siting & Licensing Hold Cost (\$/kW/yr)	\$3	\$3	\$4	\$5
Construction Cost (\$/kW)	\$985	\$1,240	\$1,700	\$2,060
Operating Cost (\$/kW/yr)	\$21	\$27	\$37	\$44
Operating Life (yrs)	50	50	50	50
Energy Cost (mills/kWh) ^a	19	32	43	53

^a Levelized revenue requirements, based on average energy.

Experience demonstrates that hydropower development can produce substantial adverse impacts on the stream environment, especially for native fish and wildlife. Section 4(e)(2) of the Northwest Power Act specifically requires the Council to take such impacts into consideration in developing its power plan. In addition, the Council is required by Section 4(h) of the Act to include in its fish and wildlife program measures to "protect, mitigate and enhance" fish and wildlife in the Columbia River Basin.

The Council expects that all new hydropower projects constructed in the region will comply fully with the conditions of development set forth in Section 1103(a) of the fish and wildlife program and in Appendix II-B of the 1986 Northwest Power Plan. The Council's estimates of the cost and availability of new hydropower include consideration of the costs and performance effects of required mitigation measures, such as minimum in-stream flows and fish screens.

The Council's estimates also take into account the Council's protected areas rule. The protected areas rule designates certain river reaches where hydropower development would have unacceptable risk of loss to fish and wildlife species of concern, their productive capacity or their habitat. The estimates include only those projects that can be developed in compliance with the rule. The Council's hydroelectric estimates also incorporate the fact that projects

3/ The costs quoted are based on average energy and are used only to establish a preliminary estimate of resource cost-effectiveness. The Council's decision model accounts for different values of the firm and nonfirm energy production of hydropower resources.

meeting the fish and wildlife provisions of the power plan and fish and wildlife program may have other impacts that would preclude state or federal licensing.

The Council recognizes that even with proper siting and full compliance with

the required mitigation measures, hydropower projects will have some impact on the environment.

The hydropower assessments are based on the best information presently available to the Council. Information concerning hydropower sites and non-

hydropower stream values is continually being refined. Accordingly, the Council will periodically reassess the cost and availability of new hydropower. However, the Council expects future changes in the estimated cost and availability of new hydropower to be relatively minor.

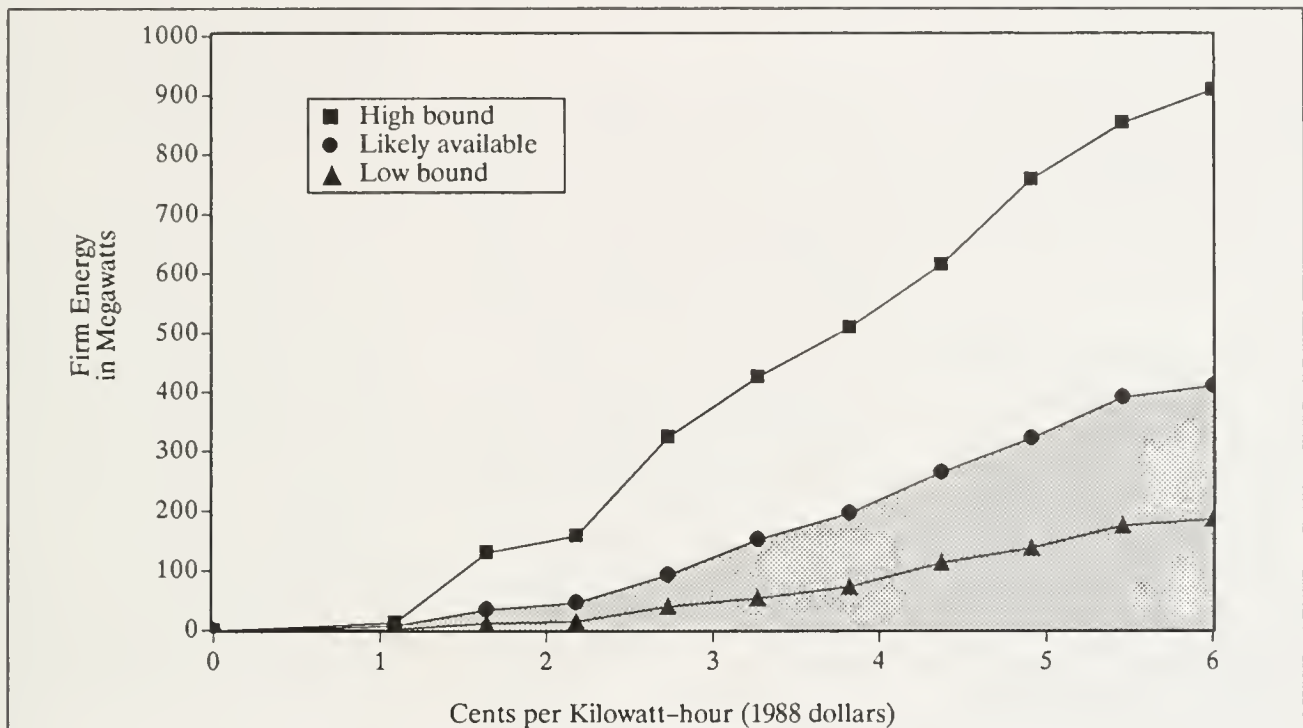


Figure 4-3
Availability and Cost of New Hydropower

Municipal Solid Waste

Plants fueled by municipal solid waste (MSW) produce about 10 megawatts of energy in the Northwest. Several additional plants are under construction. A study of the cost and availability of electricity generation using municipal solid waste was undertaken as part of a general assessment of biomass resources for the 1983 plan. This assessment indicated that sufficient MSW to generate about 360 megawatts would be available by 1990, increasing to about 380 megawatts by the year 2000. Energy from MSW was not included in the resource portfolios of either the 1983 or the 1986 plans because

of uncertainties regarding the ability to develop this resource. A reassessment of the cost and availability of municipal solid waste generation of electricity will be undertaken for the next plan.

Solar

Assessments of the availability and cost of electricity from solar-thermal and solar-photovoltaic sources were undertaken for the 1983 and 1986 power plans. Solar was not included in the resource portfolios primarily because the estimated cost of electricity from solar generating equipment at Northwest sites far exceeded the estimated cost of electricity

from new coal plants. Though costs had declined, and equipment performance had improved by 1986, the estimated cost still exceeded new coal units by factors of 3 to 8. Because of continuing equipment improvements and cost reductions, a reassessment of the cost, performance and availability of solar-thermal and solar-photovoltaic electric generation will be undertaken for the next plan.

Wind

Assessments of the availability and cost of wind-derived electricity were undertaken for the 1983 and 1986 power plans. Wind was not included as a cost-effective

resource in 1983 because of uncertain cost and performance of wind turbines and the lack of information on Northwest wind resources. Since 1983, the reliability and availability of wind turbines have been demonstrated, and favorable Northwest sites have been characterized. Wind was not included in the resource portfolio of the 1986 plan only because the estimated cost of wind-generated electricity exceeded the cost of coal by a factor of 1.2, even for the most favorable sites. Because of declining capital and operating costs, a reassessment of the costs and availability of wind generation will be undertaken over the next two years.

Wood

One utility-operated generating plant using wood residue (the 45-megawatt Kettle Falls Generating Station) operates in the region. In addition, the output of several small, stand-alone, wood-fired plants operated by independent power producers is contracted to regional utilities. Many cogeneration projects in the region use wood as a fuel.

Studies by the Council estimate that wood residue resources (waste wood from logging and milling) are sufficient to support generation of about 215 megawatts, exclusive of existing wood-fired projects. Cogeneration plants fired by wood are more efficient than stand-alone plants. Moreover, wood residue is often produced at plants processing wood products, which also provide cogeneration opportunities. For these reasons, the Council has assumed that regional wood residue resources would be used to support new cogeneration development, rather than stand-alone wood-fired power plants. A

reassessment of the cost and availability of wood-waste generation will be undertaken over the next two years.

Cogeneration

Cogeneration is the sequential production of electricity and thermal energy. The thermal energy may be used for industrial process heating, space heating, hot water heating and refrigeration loads. Cogeneration may provide a more efficient use of fuel than electricity generation alone because it uses thermal energy that otherwise would be wasted. Because the value of the thermal energy can offset part of the cost of fuel and equipment, electricity can be produced with cogeneration equipment at less cost than electricity produced alone using comparable equipment and fuel.

Cogeneration is an old and well-established technology. Earlier in the century, cogeneration plants were common at manufacturing facilities that used process heat. Cogeneration, as a fraction of all power produced in the United States, peaked at about 15 percent in 1950, but declined as electric utilities developed larger, and more cost-efficient electric generating plants. Prior to PURPA,⁴ it is estimated that 7,800 to 17,300 megawatts of cogeneration capacity was installed in the United States. Development accelerated with implementation of PURPA, and more recently with the decline in natural gas prices and improvements in technology. As of 1986, about 20,000 megawatts of cogeneration had been brought on-line nationwide. About 80 percent of this capacity is fired by fossil fuels; most of the balance uses biomass and waste fuels.

The Western Systems Coordinating Council reports that about 156 megawatts of cogeneration capacity was sold to Northwest utilities at the end of 1987.⁵ An additional 93 megawatts of capacity is expected to come into service by 1992. These estimates do not represent all cogeneration capacity installed in the region, as some plants operate for self-generation and some are shut down due to low sell-back prices. Bonneville recently estimated that a total of about 790 megawatts of cogeneration capacity is installed in the region, principally in the wood and paper industries.⁶

The 1983 Power Plan included an estimated 500 megawatts of energy from new cogeneration at prices ranging from 3.5 to 6.5 cents a kilowatt-hour (1980 dollars). Of this potential, 400 megawatts would be powered by wood and other biomass resources, and 100 megawatts by fossil fuels. In the 1986 plan, the Council adjusted these estimates using information from a 1984 assessment of cogeneration potential by the Pacific Northwest Utilities Conference Committee. A range estimate was adopted because cogeneration is expected to track economic growth in the sectors where opportunities for cogeneration exist. The resulting estimates were 130 megawatts in the low load growth case to 320 megawatts in the high, all at 4.0 cents a kilowatt-hour (1985 dollars).

Declines in fossil fuel and equipment prices and development of packaged cogeneration units suited for small industrial and commercial installations suggest that the Council's estimate of cogeneration potential should be raised.

4./ Public Utility Regulatory Policies Act of 1978.

5./ Some Northwest cogenerators sell to utilities outside the region.

6./ The figures cited for cogeneration are in megawatts of capacity. It is difficult to estimate energy production for cogeneration installations since decisions to operate are based upon a number of factors such as fuel prices, retail electricity prices, electricity buyback prices and production activity. Cogeneration installations, however, tend to have high availabilities (80 percent or better) when called upon to operate.

Previous Council assessments largely relied on estimates of cogeneration potential obtained from candidate industries. These may underestimate cogeneration potential if the estimates are based on current buy-back prices and development incentives.

Since the decline of fossil fuel prices and widespread introduction of packaged cogeneration units, Bonneville has undertaken a new study of technical and economic potential and likely deployment of cogeneration in the Pacific Northwest.

The technical potential described in the Bonneville study is based on the thermal load of all industrial and commercial facilities in the region. The number of industrial facilities is taken from the 1982 Census of Manufacturers, and the number of commercial facilities from the ongoing Pacific Northwest Non-residential Energy Survey and directories of institutional and commercial establishments. Facilities are classified by energy-use characteristics and sizes. Seasonal energy use is estimated for each class of facility. A technical cogeneration potential is estimated using PURPA's plant-efficiency and thermal-energy production criteria.

The economical cogeneration potential is that portion of the technical potential that would be economical to develop. Factors influencing the economic potential of cogeneration include retail electricity prices, fuel prices, equipment cost and performance, price escalation rates and financing requirements. Assumptions were prepared for these factors using base and high-growth economic scenarios. A range of rates of return to the developer was calculated for each class for three buy-back prices (2.5, 5.0 and 7.5 cents per kilowatt-hour), two economic scenarios, and alternative cogeneration system types and sizes. Pre-

ferred system designs were selected and the likely mode of operation (self-generation versus sell-back) was determined.

The likely rate and extent of cogeneration development for each buy-back price over the 20-year planning period were estimated by applying ultimate penetration factors and penetration rates to the estimated economic potential.

The current findings of the Bonneville study, which is under review, are shown in Figure 4-4. Little potential appears to exist at a 2.5 cent buy-back price, and this would be used for self-generation. Self-generation declines as buy-back prices increase relative to retail rates. At a 5.0 cent buy-back price, in the base-case scenario, the estimated cogeneration potential is nearly 1,650 megawatts. This estimate is considerably greater than the current Council estimate (shaded area at the lower right), but within the range of previous studies. This estimate is probably not unreasonable given declines in fuel and equipment prices.

Though the Bonneville study appears to be based on sound underlying methodology, certain aspects require refinement. These include the following:

- updating the census of potential host facilities;
- calibrating estimates of cogeneration to the forecasts of sectorial economic growth used for load forecasting;
- assessing constraints that are presented by the availability of fuels, particularly wood residue and natural gas;
- ensuring that financial assumptions are fully consistent with those used for other resources;
- refining the supply curve to include better definition of available cogen-

eration between 2.5 cents and 7.5 cents per kilowatt-hour;

- reviewing market penetration assumptions; and
- exploring a broader range of developer rates of return.

It is not feasible to determine precisely the region's likely cogeneration potential. Any estimate would quickly become dated, given the number of changeable factors that affect cogeneration. It is more important to determine if cogeneration is a "small" resource of a few hundred megawatts, or a "large" resource of many hundred or perhaps several thousand megawatts of potential. This will allow the Council to better understand the likely effects of cogeneration development and to formulate appropriate resource development and acquisition policies. Additional issues that may have to be addressed if cogeneration has substantial potential, include:

- environmental impacts of cogeneration development;
- transfer of cogenerated power between utility service territories;
- effects of self-generation on non-cogenerating ratepayers; and
- establish prices (for cogeneration and other resources) that reflect the qualities of power purchased. For example, price structures should consider uncertainties of relying on natural gas as a cogeneration fuel. Prices should also reflect the relative risk assumed by the developer, purchasing utility and the region's ratepayers.

The Council plans to complete this reassessment of cogeneration potential over the next two years. Until this study is complete, the Council will retain the amount of new cogenerated energy adopted in the 1986 plan.

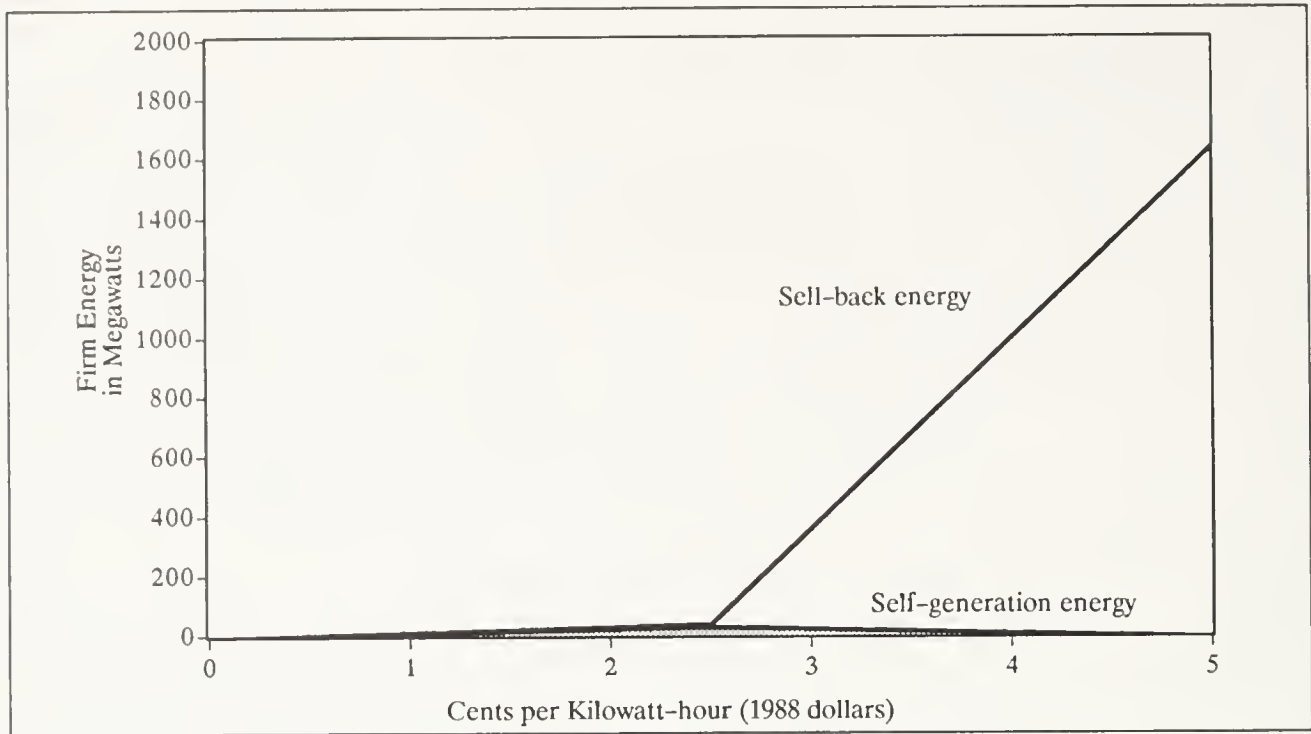


Figure 4-4
Preliminary Estimate of the Availability and Cost of Cogenerated Electric Energy

New Central-Station Thermal Resources

Electric Utility Fossil Fuel Price and Availability

The Council prepares estimates of non-electricity fuel prices for the residential, commercial and industrial sectors to use in developing load growth forecasts. The Council has adopted new estimates of the price and availability of fossil fuels for this supplement in response to major changes in fossil fuel prices since the 1986 plan. Because of the large quantities of fuel used by electric generating plants and their reliability requirements, fuel prices for these plants may differ from those of other industrial sectors. The 1986 plan contained estimates of the price and availability of coal for utility applications. This supplement intro-

duces separate estimates of fuel oil and natural gas prices for electricity generation. Development of these estimates was facilitated by information from a program to assess the cost and availability of fuels for generating plants developed by Bonneville in response to the Action Plan of the 1986 Power Plan. Additional detail is provided in Volume II, Chapter 4 of this supplement.

Distillate Fuel Oil

If used as a back-up fuel, distillate purchases by utilities would be relatively small, and prices should be similar to those for other industrial sectors. The proposed utility distillate fuel price series is therefore based on the industrial oil price series prepared for the load growth forecasts. The distillate series is obtained by adding an estimated distillate premium to the crude price series

underlying the forecasts of regional average industrial oil prices.

Distillate prices were forecast to begin at \$3.66 per million Btu⁷ in 1988. This is much lower than the \$5.70 per million Btu (1985 dollars) used in the 1986 plan, due to the drop in crude prices. Following a slight decline through 1990, as shown in Figure 4-5, distillate prices are forecast to escalate through the balance of the planning period. The average rate of escalation over 20 years is 2.5 percent.

Residual Fuel Oil

Due to limited future use, utility residual fuel oil prices are likely to resemble those for other industrial sectors. The proposed residual fuel price series is therefore the same as the regional average industrial residual fuel price series. Prices begin at \$2.72 per million Btu and

7/ British thermal unit—a measure of thermal energy.

hold relatively steady through 1990 (Figure 4-5). Beginning in 1991, real prices escalate through the end of the study period. The average rate of escalation is 2.8 percent. This is greater than the forecast

escalation rate of distillate fuel oil, as it is anticipated that improved refining technology and increased demand for lighter petroleum products will, over time, reduce the availability of heavy products

such as residual fuel oil. Also, because the residual price series begins from a smaller base than distillate, escalation rates are greater for equivalent price increases.

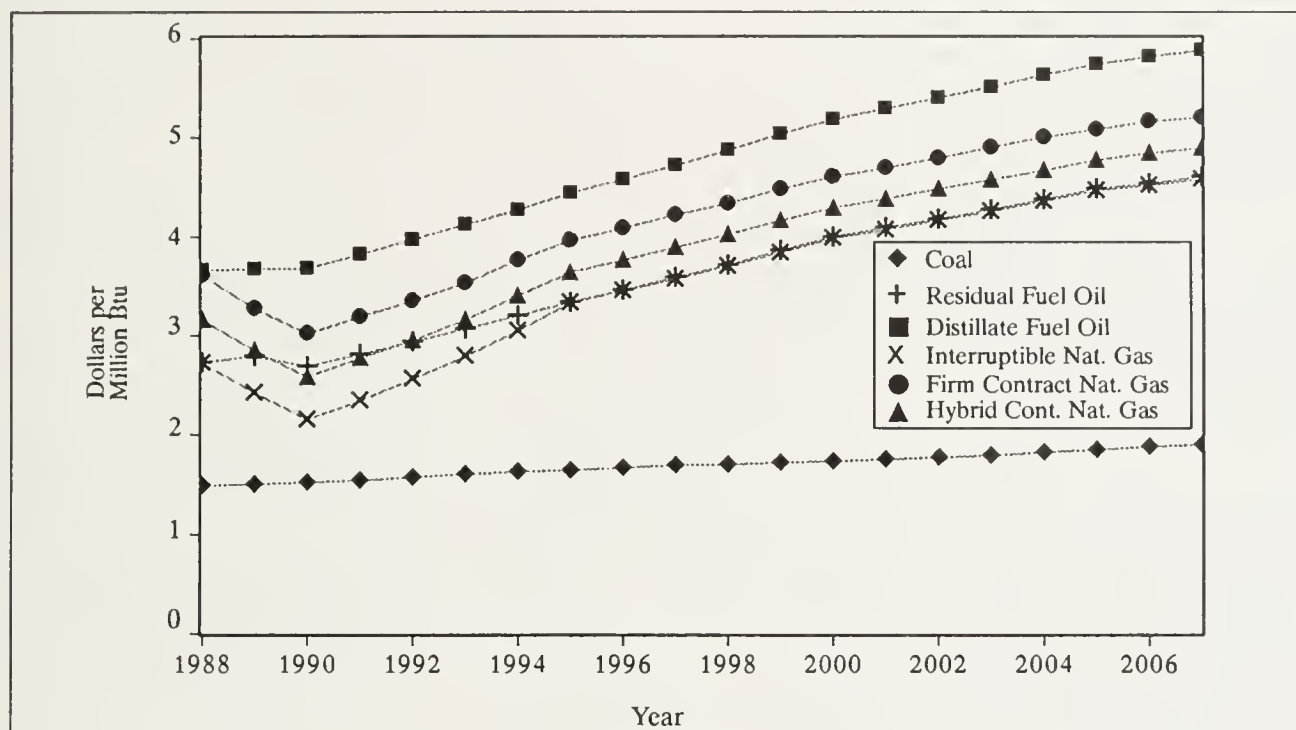


Figure 4-5
Electric Utility Fossil Fuel Prices

Natural Gas

Natural gas may be purchased under either firm or interruptible delivery contracts or purchased on the spot market. Delivery of firm (“contract”) gas is guaranteed, but at a premium price compared to interruptible. Much of the price differential is due to the cost of constructing, operating and maintaining the transmission and distribution system, and the cost of providing peak period service.

Either firm or interruptible natural gas contracts could be used to supply a gas-fired electric generating plant used primarily for base-load service. If interruptible contracts were employed, the plant would require a back-up fuel oil

supply for use during periods of gas interruption. Though gas sold as interruptible is rarely interrupted at present, this is due largely to the current surplus capacity of the natural gas transmission and distribution system. Under conditions of optimum transmission system use, delivery of interruptible gas might be suspended for as many as 100 days per year.

Use of natural gas for electric power generation in the Northwest presents an unusual supply problem. Because a natural gas-fired generating plant might be displaced by nonfirm hydropower for as much as four years out of five, there would be many years when no gas would be taken. But when the plant is needed, it might have to run at nearly full capacity

for much of the year. (Because energy, not capacity, is the reason for operating these plants, short shutdowns could be tolerated.) Gas industry representatives have suggested these plants would require reserved pipeline delivery capacity (i.e., firm service). But it should be possible to remarket some of this reserved delivery capacity during those years the plants don’t operate, thereby offsetting part of fixed delivery costs. Moreover, since these generating plants could shut down for short periods, even during poor water years, it should be possible to avoid some peaking service costs associated with firm gas contracts. The cost of gas for these plants should therefore be a hybrid of the cost of conventional firm and

interruptible contracts. The average of the firm and interruptible natural gas price forecasts is used to represent this “hybrid” price.

Interruptible gas prices follow residual fuel oil prices through the study period with the exception of the early years when the current gas surplus is worked off. Prices begin at \$2.72 per million Btu in 1986, and decline through 1990 because of the surplus (Figure 4–5). Escalation is rapid in the early 1990s as the surplus is exhausted. As equilibrium with oil is re-established in the mid-1990s, the rate of natural gas escalation declines to a rate close to that of fuel oil. The average rate of escalation over the planning period is 2.8 percent, considerably higher than the 1.8 percent used in the 1986 plan.

Firm gas prices follow interruptible prices, but at a higher level, reflecting added costs of firm service. Prices begin at \$3.61 per million Btu in 1988. The average rate of escalation over the 20-year planning period is 1.9 percent, lower than that for interruptible gas because of the relatively constant price differential between the two contract types.

The hybrid gas price series is the average of the firm and interruptible natural gas price series. Prices begin at \$3.16 in 1988, escalating at an average rate of 2.3 percent over the 20-year planning period.

If U.S. consumption of natural gas for thermal and electrical applications continues to grow, natural gas prices may increase faster than forecast. Because coal gasification technology is now commercially available, the cost of coal-derived synthetic gas may cap natural gas prices for utility applications.

Coal

The reference utility coal is Powder River Basin subbituminous coal delivered by unit train to Boardman, Oregon. The series of prices estimated for this coal comes from estimates of prices for minemouth Powder River Basin coal plus the

costs for transporting the coal to Boardman by rail. Purchase and maintenance of rail cars to transport the coal (rolling stock) is treated separately, as a fixed, fuel-delivery cost of \$8.60 per kilowatt per year.

Delivered coal prices begin at \$1.49 per million Btu (\$29.60 per ton) in 1988. This is less than the \$2.00 per million Btu used in the 1986 plan (about \$2.15 in 1988 dollars) and reflects the continuing surplus of mining capacity in the Powder River Basin. Delivered coal prices escalate at a moderate rate throughout the planning period (Figure 4–5), reaching \$1.90 by 2007. The average rate of escalation over 20 years is 1.3 percent, somewhat higher than the 0.9 percent used in the 1986 plan. Components of the long-term escalation rate include a steady, but slow increase in rail transportation rates and a fairly rapid run-up in minemouth coal prices as surplus capacity is exhausted. Because the minemouth cost represents only about 14 percent of delivered coal costs, escalation of minemouth coal prices has relatively little effect on the escalation rates of delivered coal.

Fossil Fuel Price and Availability Issues

With the exception of coal, these estimates of fossil fuel prices are intended to be reasonably representative of the region as a whole. Coal prices, because of the importance of transportation costs, are generally representative of those that might be experienced in eastern Washington or Oregon. These price series are intended to represent likely long-term trends, and do not consider possible short-term market fluctuations.

There appears to be abundant natural gas for the long-term at the producer level. However, because natural gas is generally considered to be depletable, comes from outside the region and is subject to transportation constraints, it may be unwise to rely too heavily on gas for expanding the region’s electric gen-

erating capacity. There have been several proposals to reduce the risk associated with increased use of natural gas. These include using combined-cycle generating plants that could convert to coal gasification; purchase of long-term contracts with gas producers; and limiting new gas-fired capacity to some proportion of new resource requirements (similar to California’s resource diversity policies). The long-term availability of natural gas will be investigated by the Council following issue of this supplement. This activity is intended to supplement Bonneville’s investigations of fossil fuel price and availability.

Environmental concern regarding fossil fuel use, particularly the possibility of global warming from increased concentrations of carbon dioxide and other “greenhouse” gasses in the atmosphere, has focused interest on the advisability of continued development of fossil-fuel-fired generating resources. These issues will be considered by the Council for the next plan. Natural gas is generally cleaner than other fossil fuels. It releases less carbon dioxide and other combustion products (except oxides of nitrogen) per unit of energy released.

Electric Generation Using Natural Gas

Historically, natural gas has not played a substantial role in meeting the region’s electrical loads. The region has about 1,190 megawatts of gas-fired capacity, including one combined-cycle plant and several simple-cycle combustion turbines. But because of the relatively high cost of natural gas in the past, these plants have been limited to meeting peaking loads, providing emergency capacity and for firming nonfirm hydro-power.

Gas-fired generating equipment generally has short lead times, small module sizes, low capital costs and modest environmental effects. These qualities, plus

declines in natural gas prices and relaxation of federal constraints on the use of natural gas to generate electricity suggest a greater future role for electric generation using natural gas in the region. Promising applications include expanded use of combustion turbines to firm secondary hydropower; use of combustion turbines to meet unexpected high rates of load growth; and use of combined-cycle plants for base load generation of electricity.

Technologies Using Natural Gas

At present, simple-cycle combustion turbines and combined-cycle combustion turbines show the greatest potential for natural gas electricity generation. New models introduced since 1986 provide improved operating efficiency. The Bonneville Power Administration, in response to the 1986 Action Plan, has completed a study of the cost and performance of representative combustion turbine and combined-cycle plants. For these reasons, the Council has reassessed the cost and performance of simple- and combined-cycle combustion turbines.

Simple-Cycle Combustion Turbine

The new General Electric MS7001F combustion turbine is the basis for the Council's revised estimates of combustion turbine cost and performance. This turbine is the first of a new generation of high-temperature, heavy-duty combustion turbine designs offering improved reliability and fuel-use efficiency. These machines are in the 135 - 150 megawatt capacity range and feature efficiencies of greater than 30 percent⁸ in simple-cycle

configuration. Machines of this type will also be offered by ASEA Brown Boveri, Siemens-Kraftwerk Union and Westinghouse-Mitsubishi.

The planning assumptions for the representative simple-cycle combustion turbine are shown in Table 4-3. Additional detail is provided in Volume II, Chapter 4 of this supplement.

Combined-Cycle Combustion Turbine

The General Electric STAG 207F combined-cycle plant is the basis for the Council's revised estimates of combined-cycle combustion turbine cost and performance. This plant uses the high-temperature, heavy-duty combustion turbine described above. This plant uses two combustion turbines, one heat-recovery steam generator and one steam turbine generator. The generic combined-cycle plant consists of twin units installed near Hermiston, Oregon. The plant includes site improvements, weather enclosure, water supply, cooling towers, a switchyard, a gas pipeline spur and transmission line linking the plant with the grid.

The planning assumptions for the representative combined-cycle combustion turbine are shown in Table 4-3. Additional detail is provided in Volume II, Chapter 4 of this supplement.

As with all generation resources, the actual site and site characteristics can affect capital costs significantly. This is most apparent with both simple- and combined-cycle combustion turbines since the capital costs are comparatively low and sensitive to site characteristics. For example, installations at sites adja-

cent to natural gas pipelines and existing switchyards would have lower capital costs than at sites remote from natural gas pipelines and electrical transmission lines.

Equipment can have a significant effect on capital costs, as well. For example, the new high-temperature, heavy-duty machines have a higher per-kilowatt purchase price than older model machines. However, the newer machine offers greater efficiency. In addition, newer designs of aircraft-derivative machines are entering the utility marketplace at competitive purchase prices. These units are available in conventional and steam-injected configurations, and may prove superior to the high-temperature, heavy-duty machines for certain applications.

Confronted with these broad choices, the Council and Bonneville have elected to develop and use, for analysis purposes, "upper bound" capital cost estimates for combustion turbine technologies. These estimates include costs for electrical integration, pipeline construction, site purchase, site development, and measures to mitigate the impact of the resource on the host community or area. The "lower bound" of capital cost estimates is less certain and requires additional evaluation. The Council and Bonneville intend to explore the costs and technical characteristics of alternative combustion turbine sites and designs in order to provide a better understanding of the range of costs and performance characteristics to be expected of these machines.

8./ Higher heating value of fuel basis.

Table 4-3
Combustion Turbine and Combined-cycle Projects: Planning Characteristics

	SIMPLE-CYCLE COMBUSTION TURBINES	COMBINED-CYCLE COMBUSTION TURBINES
Primary Fuel	Natural Gas	Natural Gas
Alternate Fuel	No. 2 Fuel Oil	No. 2 Fuel Oil
Fuel Inventory	No. 2 Fuel Oil for 14 days	No. 2 Fuel Oil for 14 days
Location	Operation at rated capacity Hermiston, Oregon	Operation at rated capacity Hermiston, Oregon
Rated Capacity (Net MW @ 59° F)	2 units @ 139 MW/unit	420 MW
Peak Capacity (Net MW @ 35° F)	2 units @ 152 MW/unit	452 MW
Heat Rate @ HHV (Btu/kWh)	11,480	7,620
Availability (%)	85	83
Seasonality	Winter peaking	Winter peaking
Siting & Licensing Lead Time (mos)	24	24
Siting & Licensing Shelf Life (yrs)	5	5
Construction Lead Time (mos)	24	36
Siting & Licensing Cost (\$/kW)	\$5	\$6
Siting & Licensing Hold Cost (\$/kW/yr)	\$0.50	\$0.40
Construction Cost (\$/kW) ^a	\$530	\$620
Fuel Inventory Cost (\$/kW)	\$14	\$9
Fixed Fuel Delivery (\$/kW/yr)	None	None
Variable Fuel Cost (mills/kWh)	36.3 ^b	24.1 ^c
Fixed O&M (\$/kW/yr)	\$2.00	\$5.40
Variable O&M (mills/kWh)	0.1	0.3
Capital Replacement	Included in O&M	Included in O&M
Operating Life (yrs)	30	30

^a Construction costs exclude interest and escalation incurred during construction.

^b "Hybrid" gas contract (for backing up nonfirm hydropower).

^c "Hybrid" gas contract (for backing up nonfirm hydropower). Firm gas service (for base-load plant) would be 27.9 mills per kilowatt-hour.

Limits to Development

The geographic location of sites for new combustion turbines or combined-cycle plants is limited by the regional gas transmission system. But the availability of sites does not generally appear to be a constraint, except for some noise limitations. Plants could be built at existing or licensed thermal sites in the region.

A much more important constraint may be long-term availability of low-cost natural gas. The concern is not so much with the continued supply of natural gas at the wellhead—generally considered adequate for several decades—as it is with transmission of gas to generating sites.

The capabilities of the regional natural gas transmission system to support new electric power generation are poorly understood at present. It is believed that the system can supply firm (contract) gas, sufficient to generate about 1,000 average megawatts of energy from new combined-cycle plants, and interruptible gas sufficient to generate about 2,000 average megawatts from new simple-cycle combustion turbines. Following issue of this supplement, the Council will begin an assessment of the long-term availability of natural gas for electric power generation.

There may also be environmental constraints on expanded use of natural gas for electricity generation. Combustion of natural gas releases nitrogen oxides and carbon dioxide. Nitrogen oxides are an acid rain precursor, and nitrous oxide and carbon dioxide are thought to be important contributors to global warming. These releases may eventually constrain use of natural gas and other hydrocarbon fuels. But because natural gas contains proportionally less carbon than coal, natural gas combustion produces less carbon dioxide than combustion of an equivalent amount of coal. For this (and

other) reasons, natural gas may be preferred to coal. The Council will assess the implications of global warming and other environmental effects of fossil fuels for the next power plan.

Electric Generation Using Coal

The Northwest power system receives output from 13 coal-fired units totaling 6,702 megawatts of nameplate capacity. The regional shares of these plants supply 3,957 megawatts of peak capacity and 3,154 megawatts of energy.⁹

Except for mines adjacent to the Centralia Generating Station, little coal is mined in the region. However, proven reserves of low-sulfur coal far in excess of those required to meet electricity needs for the foreseeable future are available near the region. Because of the abundance of coal and the availability of proven technology, coal-fired power plants were used as the basis for long-term marginal resource costs in the 1983 and 1986 plans.

The 1986 plan included 5,425 megawatts of new coal generation. This amount represented the difference between new resources other than coal considered to be available in 1986, and the new resource requirements of the regional high load growth case. Because of reservations concerning this scale of new coal development, the plan also included action items for confirmation and further investigation of alternative resources, and recommendations for development of a resource acquisition process that would encourage the development of renewable and other lower-cost resources prior to the construction of coal plants.

Because of increasing environmental concerns about use of fossil fuels, particularly global warming, the Council has not increased the amount of new coal in the resource portfolio beyond the level of the 1986 plan, pending an assessment

of the seriousness of the environmental impacts, the cost and available mitigation measures and the cost and availability of alternative resources. Though the Council intends to assess the limits to the use of coal for energy production in the region, the costs and performance characteristics of new coal-fired power plants will, in the meantime, be used to model the characteristics of the regional long-term marginal resource.

Cost and Performance of Technologies Using Coal

Conventional pulverized-coal-fired power plants, atmospheric fluidized-bed power plants, and gasification combined-cycle power plants are the three commercially available means of producing electricity from coal. (Other designs are available, but their use is generally restricted to small-scale power plants.) The Council reviewed the planning characteristics adopted for the representative pulverized-coal plants in the 1986 plan and has adopted new planning assumptions for atmospheric fluidized-bed plants and a coal-gasification combined-cycle plant. Additional detail of this assessment is provided in Volume II, Chapter 4 of this supplement.

Pulverized-Coal-fired Power Plants

The pulverized-coal-fired steam-electric power plant is an established technology for producing electricity. Although a mature technology, enhancements in plant control, efficiency and reliability have improved the cost and performance of new plants compared with earlier designs. A range of unit sizes is available, allowing additions to be matched to load growth.

Two representative pulverized-coal plants are considered. One is a twin-unit design of 603 megawatts net capacity per unit. This size is typical of the larger

plants constructed in recent years. The second generic plant is a twin-unit design of 250 megawatts net capacity per unit. This plant is typical of the smaller units completed in recent years, and offers the advantages of shorter lead time, smaller module size and somewhat greater reliability. The larger units retain cost advantages. Planning characteristics for these plants are shown in Table 4-4.

Atmospheric Fluidized-Bed Plants

Atmospheric fluidized-bed combustion (AFBC) coal-fired power plants scavenge sulfur from the burning coal through injection of limestone into the furnace. With certain coals, this design can meet current federal New Source Performance Standards for pollution without use of flue gas desulfurization equipment, thereby reducing capital and operating costs. AFBC units became available for utility application during the early 1980s, and the cost and performance of a small unit were included in the 1986 plan. Because of subsequent utility-scale demonstration projects and further development of AFBC designs, the costs and performance characteristics of two, more advanced AFBC plants are included in this supplement.

One is a single-unit plant of 200 megawatts nominal capacity; the second a twin-unit plant of 500 megawatts nominal capacity per unit. Both use a subcritical, reheat steam cycle, similar to the pulverized-coal plants. The AFBC plant characteristics are based on a study of alternative designs recently prepared for the Electric Power Research Institute. The 200-megawatt plant is similar in scale to recent AFBC demonstration projects. The twin 500-megawatt unit plant is much larger than recent AFBC demonstration projects and incorporates experience gained with smaller designs.

9/ Excluding the J.E. Corette plant of Montana Power Company and the Montana Power Company shares of the Colstrip units.

Table 4-4
Pulverized-Coal Power Plants: Planning Characteristics

	TWIN 250-MW UNITS	TWIN 603-MW UNITS
Primary Fuel	Subbituminous Coal	Subbituminous Coal
Alternate Fuel	None	None
Fuel Inventory	90 days coal @ rated capacity	90 days coal @ rated capacity
Location	Hermiston, Oregon	Hermiston, Oregon
Rated Capacity (Net MW)	2 units @ 250 MW/unit	2 units @ 603 MW/unit
Peak Capacity (Net MW)	262 MW/unit	633 MW/unit
Heat Rate (Btu/kWh)	11,010	10,860
Availability (%)	77	75
Seasonality	Insignificant seasonal variation	Insignificant seasonal variation
Siting & Licensing Lead Time (mos)	48	48
Siting & Licensing Shelf Life (yrs)	5	5
Construction Lead Time (mos to first unit/complete plant)	60/72	72/84
Siting & Licensing Cost (\$/kW)	\$32	\$23
Siting & Licensing Hold Cost (\$/kW/yr)	\$0.90	\$0.80
Construction Cost (\$/kW) ^a	\$1,670	\$1,210
Fuel Inventory Cost (\$/kW)	\$44	\$35
Fixed Fuel Delivery (\$/kW/yr) ^b	\$8.60	\$8.60
Variable Fuel Cost (mills/kWh)	16.4	16.2
Fixed O&M (\$/kW/yr)	\$32.80	\$20.50
Variable O&M (mills/kWh)	3.0	1.9
Capital Replacement	Included in O&M	Included in O&M
Operating Life (yrs)	40	40

^a Construction costs exclude interest and escalation incurred during construction.

^b Annual unit cost of purchase and maintenance of unit train rolling stock.

Representative planning characteristics for the two AFBC plants are shown in Table 4-5. Unit capital costs for the twin 500-megawatt unit plant are lower than those of the single 200-megawatt unit, as might be expected for larger and replicate units. These compare with the estimated capital costs of the generic twin 603-megawatt pulverized-coal plant. Because of the lack of experience with AFBC units of this size, the figures for the 500-megawatt unit are provided for information only and were not considered for development of the resource portfolio.

Coal-Gasification Combined-Cycle Power Plant

A gasification combined-cycle (GCC) plant consists of a coal-gasification plant and a combined-cycle combustion tur-

bine power plant. The gasification plant produces synthetic gas used to fuel the combined-cycle combustion turbine plant. Attractive features of GCC plants include a high degree of modularity, improved control of atmospheric emissions and high energy conversion efficiencies. The combustion turbine and combined-cycle sections can be installed prior to the gasification plant and operated on natural gas until fuel prices or load conditions indicate that installation of the gasification section would be economical. The gasifier is therefore able to impart fuel flexibility to the highly efficient combined-cycle plant. The coal-gasification combined-cycle plant concept has been successfully demonstrated at the 100-megawatt Coolwater Plant in California.

The representative gasification combined-cycle power plant will have a 419-megawatt capacity when completed. The plant could be constructed in phases or as a complete entity. If phased, the first phase would consist of a twin-unit combustion turbine plant fired by natural gas. In the Northwest, this plant could be used for firming nonfirm hydropower or meeting unexpected rates of load growth. As loads and frequency of operation of the combustion turbine plant increase, the turbines could be converted to combined-cycle operation for greater efficiency. This would require adding heat-recovery steam generators, a steam turbine generator and a heat-rejection system. If natural gas prices rise, the third and final phase, a coal-gasification plant, could be added to allow the plant to operate on coal.

Table 4-5
AFBC^a Coal-fired Power Plants: Planning Characteristics

	SINGLE 197-MW UNIT	TWIN 509-MW UNITS
Primary Fuel	Subbituminous Coal	Subbituminous Coal
Alternate Fuel	None	None
Fuel Inventory	90 days coal @ rated capacity	90 days coal @ rated capacity
Location	Hermiston, Oregon	Hermiston, Oregon
Rated Capacity (Net MW)	1 unit @ 197 MW/unit	2 units @ 509 MW/unit
Peak Capacity (Net MW)	Not available	Not available
Heat Rate (Btu/kWh)	9,890	9,850
Availability (%)	81	74
Seasonality	Insignificant seasonal variation	Insignificant seasonal variation
Siting & Licensing Time (mos)	48	48
Siting & Licensing Shelf Life (yrs)	5	5
Construction Time (mos to first unit/complete plant)	64	76
Siting & Licensing Cost (\$/kW)	\$41	\$23
Siting & Licensing Hold Cost (\$/kW/yr)	\$1.40	\$0.50
Construction Cost (\$/kW) ^b	\$1,760	\$1,270
Fuel Inventory Cost (\$/kW)	\$32	\$32
Fixed Fuel Delivery (\$/kW/yr) ^c	\$8.60	\$8.60
Variable Fuel Cost (mills/kWh)	14.7	14.7
Fixed O&M (\$/kW/yr)	\$37.10	\$20.70
Variable O&M (mills/kWh)	4.8	3.1
Capital Replacement (\$/kW/yr)	Included in O&M	Included in O&M
Operating Life (yrs)	30	30

^a AFBC – Atmospheric fluidized-bed combustion.

^b Construction costs exclude interest and escalation incurred during construction.

^c Annual cost of purchase and maintenance of unit train rolling stock.

Representative planning characteristics for a coal-gasification combined-cycle plant are shown in Table 4-6. Phase I consists of twin 135-megawatt, heavy-duty, high temperature combustion turbines similar to the units described in the previous (natural gas) section. Phase I siting and licensing costs and lead times assume that the site would be fully licensed for eventual construction of the gasification plant and hence are greater than those discussed earlier for natural gas combustion turbines without conversion capability. The cost of land and

common facilities to accommodate the complete gasification combined-cycle plant are included in the siting and construction costs given for the simple-cycle combustion turbine and combined-cycle phases.

The combined-cycle phase requires addition of a heat-recovery steam generator, a steam turbine generator, and a reject-heat removal system to the combustion turbines of the first phase. These additions are sized to the completed gasifier combined-cycle plant. Also in-

cluded is a second transmission line to accommodate the additional generating capacity. Otherwise, the plant is similar to the plant described in the previous (natural gas) section. Planning characteristics for both an incremental second phase, and a complete “gasifier-ready” combined-cycle plant are shown in Table 4-6. Because review of the original licenses and permits would likely be required, some preconstruction costs and a preconstruction lead time are shown for incremental construction.

The third phase, addition of the gasification section, includes coal handling, storage and preparation facilities, oxygen plant, coal gasifiers, gas clean-up and sulfur recovery facilities. The gas tur-

bines are partially re-bladed for optimum operation with the low-Btu synthetic gas. Planning assumptions for both an incremental gasification addition and a complete gasifier combined-cycle

plant are shown in Table 4-6. The pre-construction cost and schedule for the incremental addition allows for review of the project licenses and permits prior to proceeding with construction.

Table 4-6
Coal Gasification Combined-cycle Power Plant: Planning Characteristics

	PHASE I COMBUSTION TURBINES	PHASE II COMBINED-CYCLE (INCREMENTAL/ PLANT) ^a	PHASE III GASIFIER COMBINED- CYCLE (INCREMENTAL/ PLANT) ^a
Primary Fuel	Natural Gas	Natural Gas	Subbituminous Coal
Alternate Fuel	No. 2 Fuel Oil	No. 2 Fuel Oil	Natural Gas
Fuel Inventory	14 days FO @ rated capacity	14 days FO @ rated capacity	90 days coal @ rated capacity
Location	Hermiston, Oregon	Hermiston, Oregon	Hermiston, Oregon
Rated Capacity (Net MW @ 59° F)	2 units @ 139 MW/unit	420 MW	419 MW
Peak Capacity (Net MW @ 35° F)	2 units @ 152 MW/unit	452 MW	451 MW
Heat Rate @ HHV (Btu/kWh)	11,480	7,620	9,270
Availability (%)	85	83	80
Seasonality	Winter Peaking	Winter Peaking	Winter Peaking
Siting & Licensing Time (mos)	48	12/48	12/48
Siting & Licensing Shelf Life (yrs)	5	5	5
Construction Time (mos to first unit)	24	38/38	39/39
Siting & Licensing Cost (\$/kW)	\$49	\$8/\$33	\$16/\$38
Siting & Licensing Hold Cost (\$/kW/yr)	\$0.60	Not applicable/\$0.50	Not applicable/\$0.50
Construction Cost (\$/kW) ^b	\$530	\$280/\$620	\$1,230/\$1,820
Fuel Inventory Cost (\$/kW)	\$14	\$3/\$9	\$30/\$30
Fixed Fuel Delivery (\$/kW/yr)	none	none	8.60 ^c
Variable Fuel Cost (mills/kWh)	36.3 ^d	24.1 ^e	13.8
Fixed O&M (\$/kW/yr)	\$2.00	\$5.40	\$61.20
Variable O&M (mills/kWh)	0.1	0.3	1.0
Byproduct Credit (mills/kWh)	Not applicable	Not applicable	0.2 ^f
Capital Replacement	Included in O&M	Included in O&M	Included in O&M
Operating Life (yrs)	30	30	30

^a Incremental costs do not sum to total plant costs because of cost advantages of constructing a complete plant. Incremental unit construction costs are based on the total rated capacity of the resulting plant.

^b Construction costs exclude interest and escalation incurred during construction.

^c Natural gas capacity charge plus annual cost of purchasing and maintaining unit train rolling stock.

^d "Hybrid" natural gas contract (for backing up nonfirm hydropower).

^e "Hybrid" natural gas contract (for backing up nonfirm hydropower). Firm gas service (for base-load plant) would be 27.9 mills per kilowatt-hour.

^f Receipts for elemental sulfur.

Limits to Development

Future use of coal on the scale suggested by the higher load growth forecasts presents significant questions concerning air quality impacts, site availability, coal transportation and electric power transmission.

Air Quality Effects

Coal combustion products may adversely affect air quality and may result in widespread secondary impacts to the earth's atmospheric, hydrologic and ecologic systems, and to human cultural systems. Among the combustion products of greatest concern are carbon dioxide, oxides of sulfur, oxides of nitrogen and particulates. Systems for control of nitrogen oxide, sulfur dioxide and particulates are available and in place on power plants constructed following implementation of the Clean Air Act. But no system for control of carbon dioxide is in current use on power plants. Though such systems appear to be technically feasible, they would be expensive, both in terms of capital and operating costs and in impacts on plant operating efficiency. Increasing concern regarding fossil fuel combustion products indicates a need to explicitly consider their role in determining the availability of new fossil fuel generation.

Site Availability

The availability of sites for coal-fired power plants is more constrained than for any other generating technology, with the possible exception of nuclear. Factors that must be considered include the ability of the airshed to absorb the atmospheric discharges of the plant, availability of water for cooling, proximity to the transmission grid, proximity of rail or water transportation for coal (if remote from the minemouth), and availability of land for disposal of ash and flue gas desulfurization products. Only a limited number of regional sites can adequately meet these requirements.

Coal Transportation

Because of the large volumes of coal required by a central-station coal-fired power plant, rail or water coal transportation routes must be available if the plant is to be remotely sited from coal mines. Consideration must be given not only to the proximity of the plant site to rail or water services, but also to the ability of the selected mode of transportation to provide a reliable supply of coal. In the case of rail transportation, the ability of the current rail system to safely and reliably deliver coal in the amounts required by higher load growth cases is not clear (the representative 1,200 megawatt coal plant described earlier would require about 180 rail cars of coal per day, when in full operation). Coal could be delivered to regional sites by barge, but the sources of supply would be distant and more costly than sources accessible by rail.

Electric Power Transmission

An alternative to transportation of coal into the region would be the siting of coal plants at the minemouth outside the region. This, however, would require construction of a long-distance, high-voltage transmission line to tie the plants into the regional grid. Construction of such lines is expensive, and their siting is extremely difficult.

The Council, following issue of this supplement, will assess factors affecting the availability of coal for future power generation, beginning with consideration of global warming implications.

Imports

New firm power imports were not included in the resource portfolio of either the 1983 or the 1986 power plans because of lack of information on the long-term cost or availability of imported firm power (other than that provided by existing contracts or the regional share of out-of-

region power plants owned by regional utilities). Following the 1986 plan, the Council conducted a Western Electricity Study, which identified opportunities for new, potentially mutually beneficial electrical transactions between western regions. Some of the possibilities include:

- Interim purchase of the capability of British Columbia resources constructed in advance of need. These resources might include any of several proposed large-scale hydroelectric projects and coal-fired power plants. Though none of these resources are presently in the resource portfolio, a recent update of the "B.C. Hydro Twenty-Year Resource Plan" provides information that might allow the development of estimates of the amount and timing of these resources.
- Securing the capability of California natural gas-fired steam electric plants for use as a back up for Northwest nonfirm hydropower. Such plants may provide firming capability at lower cost than the new combustion turbines used as the basis for the Council's studies.
- Improved coordination of the entire Columbia River hydropower system by the United States and Canada. Current discussions between Bonneville and B.C. Hydro could achieve a limited coordination agreement by 1989. Full coordination could provide additional firm energy, but might adversely affect operation of the B.C. Hydro system.
- Import of coal or of electricity from coal-fired power plants from Alberta. With its large coal reserves, Alberta could be a source of coal for coal-fired power plants, or of electricity from minemouth coal-fired power plants. The latter would re-

quire upgraded transmission interties between the Northwest and Alberta. Although electricity from Alberta coal is not specifically considered in this plan, its costs would likely compare to the cost of electricity from the generic coal-fired power plants using Powder River Basin coal.

- Import of natural gas from Alberta for use in combustion turbines or combined-cycle plants. Much of the natural gas used in the Northwest originates in British Columbia. Expanded use of Alberta gas would require construction of additional gas transmission capacity.

These possibilities have not been sufficiently analyzed to determine the extent to which the region should rely on imports to meet future electrical needs. The cost and availability of new firm power imports will be considered by the Council in a future revision to the plan.

WNP-1 and WNP-3

In the 1986 plan, the Council found that Washington Public Power Supply System nuclear projects 1 and 3 (WNP-1 and WNP-3) could be cost-effective to the region. The value of these plants was based on the costs to complete and operate WNP-1 and WNP-3, versus the higher costs of building alternative resources. The plants were found to have value, particularly in the higher load growth cases.

However, the Council also determined that there were significant barriers to

preserving and completing these projects. The Council consequently concluded that the plants should be preserved as potential resource options. The Council called for actions to address and eliminate these barriers and, in the meantime, to reduce preservation costs to the minimum level consistent with the role of the plants.

Since issue of the 1986 plan, problems precluding further financing of these plants apparently have been resolved. New bonds for partial refinancing of WNP-1 and WNP-3 are scheduled to be issued in late spring 1989. The Council will reassess the cost-effectiveness and role of these plants for its next power plan.

Hanford Generating Project Repowering

The Hanford Generating Project (HGP) is a 860-megawatt steam electric generating plant built to use steam produced by the U.S. Department of Energy (DOE) N-Reactor. It is on the U.S. Department of Energy Hanford Reservation in south-central Washington. The project consists of two low-pressure steam-turbine generators, a once-through cooling system that uses water from the Columbia River, and support facilities. It connects to the N-Reactor by steam supply and condensate return lines, but is otherwise physically separate from the N-Reactor complex. HGP does not contain radioactive material.

HGP operated from 1966 to 1986. In January 1987, the N-Reactor was shut down for safety improvements. Following the announcement by DOE in February 1988 that the N-Reactor would be placed in "cold stand-down condition" for an undetermined length of time, actions were begun to place HGP in a condition permitting extended preservation.

Because the Hanford Generating Project is reported to be in excellent condition, it may be cost-effective to provide a replacement steam source. The resulting plant could be designed to operate either as a base load plant or to provide back up for nonfirm hydropower. Construction could be timed to mesh with regional need, though this would require preservation expenditures for the interim period. Bonneville has recently completed a conceptual engineering study of repowering alternatives. This study shows that repowering of HGP is technically feasible. On the basis of this conclusion, an analysis of contractual and legal issues, environmental requirements and an economic analysis, Bonneville has prepared a draft recommendation that HGP be preserved. Bonneville intends to make a final recommendation in 1989. The Council will assess the cost-effectiveness of HGP repowering alternatives and the possible role of HGP in the resource portfolio when developing its next power plan.

Chapter 5

Resource Portfolio

The concept of a resource portfolio is analogous to an investor's portfolio. The Council selects a possible mix of resources to meet future energy needs, much like the investor choosing investments. Both diversify their investments to manage uncertainties and reduce risks. Both have investment criteria. The Council seeks the lowest system cost,¹ and the investor desires the greatest return. Just as an investor tries to minimize risk, the Council tries to maximize flexibility as a strategy to manage risk. Finally, both must use judgment to include in the decisions those attributes that cannot be quantified.

In developing this supplement to the Northwest Power Plan, the Council was required to forecast a variety of future conditions. These include estimates of future economic activity, the amount of electricity required to provide energy services, future fuel prices, resource costs and availability, and the performance of all existing and anticipated resources. Such predictions are by their nature subject to substantial uncertainty. More precise analytical methods and forecasting techniques will not alter the fact that the future is inherently unknowable. For this reason, the Council attempts to identify and quantify the major areas of uncertainty by estimating a range of possible outcomes. The Council then evaluates specific risk management strategies to address those uncertainties.

Predictions based on any one scenario almost certainly will be wrong. Therefore, the Council, in forecasting Bonneville Power Administration's and the region's future load growth, characterizes the range of uncertainty with four basic load scenarios: high future load growth; medium-high; medium-low; and low. Since actual loads are not likely to grow along any one scenario, the Council analyzed hundreds of alternative ways load growth

actually could occur. These are called load paths.

The major significance of a resource portfolio is not the amount and type of resources included for the year 2010. Because of the time frames involved, the accuracy of these long-range predictions is particularly poor. A resource portfolio is significant primarily as a guide for actions taken in the near term. Because of the major uncertainties that always will remain, the Council and the region are forced to take risks in choosing new resources. It is important to recognize that sometimes inaction is as risky or riskier than action. Resources take a long time to develop and to come online. Both conservation and generating resources have lead times. Consequently, if the Council and the region are to meet future needs for electric power, action must be taken well in advance of the actual need for resources.

Developing a resource portfolio establishes a framework for analyzing alternative resource strategies. Each strategy has its own economic costs and environmental consequences. Part of the Council's task is to structure and quantify an analytical framework for the resource portfolio. That framework formalizes the frequent trade-offs inherent in power planning. But many environmental, institutional and political aspects of power planning are not easily quantified. That means the Council also must make non-analytical judgments about developments in these areas, when it weighs what resources to include in the portfolio.

The resource portfolio provides another function. It is a benchmark against which new resources, not currently in the plan, can be evaluated. If new resources are lower cost than the resources included in the resource portfolio and meet the oth-

er requirements of the Northwest Power Act, they will be included in a future plan or acquired immediately to meet near-term needs.

The Council includes resources in the resource portfolio that minimize the cost of providing electric energy services over the next 20 years. In developing this portfolio, the Council has evaluated the resource needs of Bonneville's current customers, the region as a whole and the investor-owned utilities as a group. By comparing the resource needs of the Administrator with those of the region as a coordinated system, the Council identifies opportunities for reducing regional costs through coordinated utility actions. During comment on this supplement, the region's utilities expressed concerns that changes in resource quantities from the 1986 resource portfolio were not warranted without further study and discussion. For this reason, the resource portfolio in the supplement does not identify all resources needed to meet all possible future load growth paths. This is the Council's next step.

Bonneville's Energy Requirements

The Administrator's need for new resources is developed by subtracting Bonneville's existing resources from each load forecast for Bonneville's current customers. The resulting resource requirements, shown in Figure 5-1, include the need for replacements of some existing resources that will go out of service during the next 20 years. Figure 5-1 shows that Bonneville's current surplus is between 250 and 1,000 average megawatts. The total amount of resource additions it might require by the year 2010 ranges from zero in the low to about 4,400 average megawatts in the high. Figure 5-1 also shows the points where

1./ System cost is defined as an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, distribution and transmission costs, waste disposal costs, end-of-cycle costs, fuel costs and quantifiable environmental costs. System cost also takes into account projected resource operations based on appropriate historical experience with similar measures or resources.

Bonneville's need would exceed existing resources in each load scenario. Current Bonneville contracts for power sales contain callback provisions or provisions to convert to capacity-energy exchanges. The callback of energy and the conversion to a capacity exchange is assumed to

happen when Bonneville needs power. These actions are embodied in Figure 5-1. These contracts reduce Bonneville's near-term surplus, but callback and conversions to exchange extend the time when additional new resources are needed.

Assuming Bonneville secures no more conservation than has already been acquired, the medium-high and medium-low scenarios require new resources between 1999 and beyond the planning horizon.



Figure 5-1
Bonneville Load/Resource Balance

Energy Requirements for the Region

The region's need for new resources is shown in Figure 5-2. The figure shows that while there is considerable uncertainty in the estimates of the amount of the current surplus, the region as a whole is probably surplus from 400 to 1,700 megawatts. In the medium-high and medium-low scenarios, the region would need new resources between 1995 and 2004. The four load scenarios for the region show more than 14,000 megawatts of load uncertainty in 2010.

If high loads occur, the region needs new resources as early as 1992. In the low forecast, no new resources are needed, although the region still would acquire cost-effective resources that will be lost if not developed at this time. An example of a resource opportunity that must be secured or lost is the construction of energy-efficient new buildings. Heat-loss prevention measures beyond current building codes cannot be installed cost-effectively after the building is completed. Lost opportunities must be acquired as new buildings are constructed

or processes are modified, regardless of which load scenario actually will develop.

To analyze alternative resource portfolios, the Council assumed that the high and low scenarios bound the possible range of load growth. Loads outside the high and low forecasts, while possible, are considered too unlikely to justify actions at this time. Demands between the medium-high and medium-low forecasts are most likely and considered equally probable. The probability of

loads between the high and medium-high and medium-low, 53 percent; and between the medium-low and low, 24 percent.



Figure 5-2
Regional Load/Resource Balance

In addition to the Administrator’s current customers, Bonneville also could have to serve investor-owned utility loads that may be placed on it under power sales contracts. The investor-owned utilities would have to provide Bonneville with seven years’ notice, but even with this notice, the Administrator’s actual range of load uncertainty, shown in Figure 5-3, is substantial. If the region experiences high-load growth, investor-owned utilities may need to turn to Bonneville almost immediately to meet load growth. While the seven-year notice is a firm contractual requirement, if the region as a whole goes deficit, the resulting energy shortage will affect all the region’s utilities. This is known as the “one

short, all short” concept and will accompany any regionwide power shortage. The range shown in Figure 5-3 assumes public utilities do not develop alternatives to purchasing power from Bonneville. The Administrator’s range of uncertainty could be broader. If the current efforts to minimize purchases from Bonneville continue, the Administrator’s low-load scenario could be much lower.

The Northwest Power Act requires the Council to forecast electrical energy demand and plan for resources to serve Bonneville’s customers. The plan must therefore set forth those actions Bonneville should pursue in order to meet the Administrator’s obligations. At this

time, only small loads have been placed on Bonneville by investor-owned utilities through the power sales contracts.

Consistent with the Act, the plan focuses on actions that Bonneville must undertake. However, actions outside Bonneville’s responsibility ultimately will be the responsibility of the utilities and their regulators or local governing boards. The regional perspective helps illustrate how the region’s power institutions can achieve the lowest-cost energy future. Regionwide coordination among all utilities, regulators and local governing bodies is needed to assure the lowest-cost actions to meet the collective needs of the region.

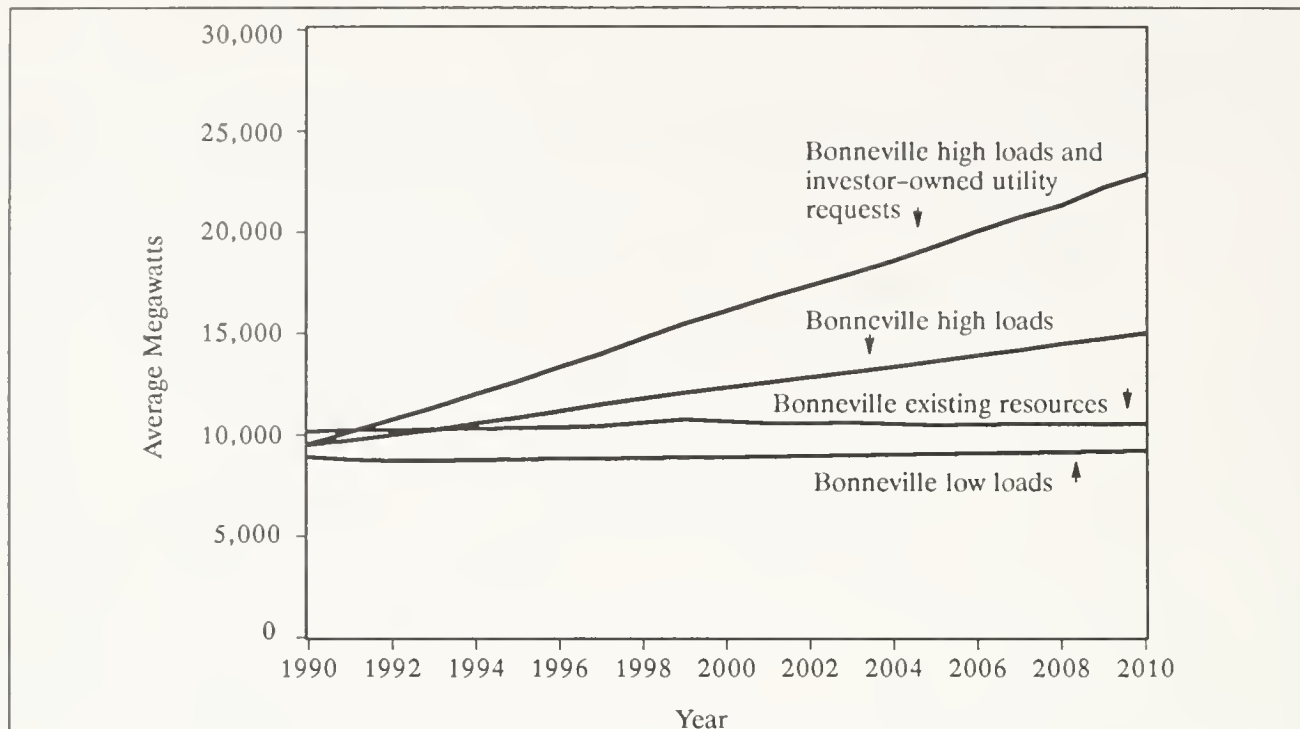


Figure 5-3
Bonneville Power Administration Range of Uncertainty

Investor-owned Utility Energy Requirements

There are six companies in the Northwest that are owned by investors. These companies are: Idaho Power, Montana Power, Pacific Power and Light, Washington Water Power, Portland General Electric and Puget Sound Power and Light. While all six companies are privately owned they are completely independent entities with widely differing power conditions now and in the future. For this reason, it is erroneous to use the

power demand, supply and load growth for the group of six companies as representative of any one company. However, the conditions of all six investor-owned companies taken together generally indicate the power conditions that the Council would expect on average. As with any average, some utilities will experience large surpluses, while others at the same time will see large deficits. On average, investor-owned utilities as a group may be in load/resource balance while no specific company is in this condition.

Figure 5-4 shows that the current investor-owned utility surplus is from 150 to 750 megawatts. If loads grow at the high rate, the investor-owned utilities will need additional firm resources as early as 1991, but if low loads develop they will not need additional resources until 2006. Under the medium-high/medium-low scenarios, the point of needing additional resources is between 1992 and 1998. The total range of load growth uncertainty is about 8,000 megawatts by the year 2010. This is 55 percent of the region's load uncertainty.

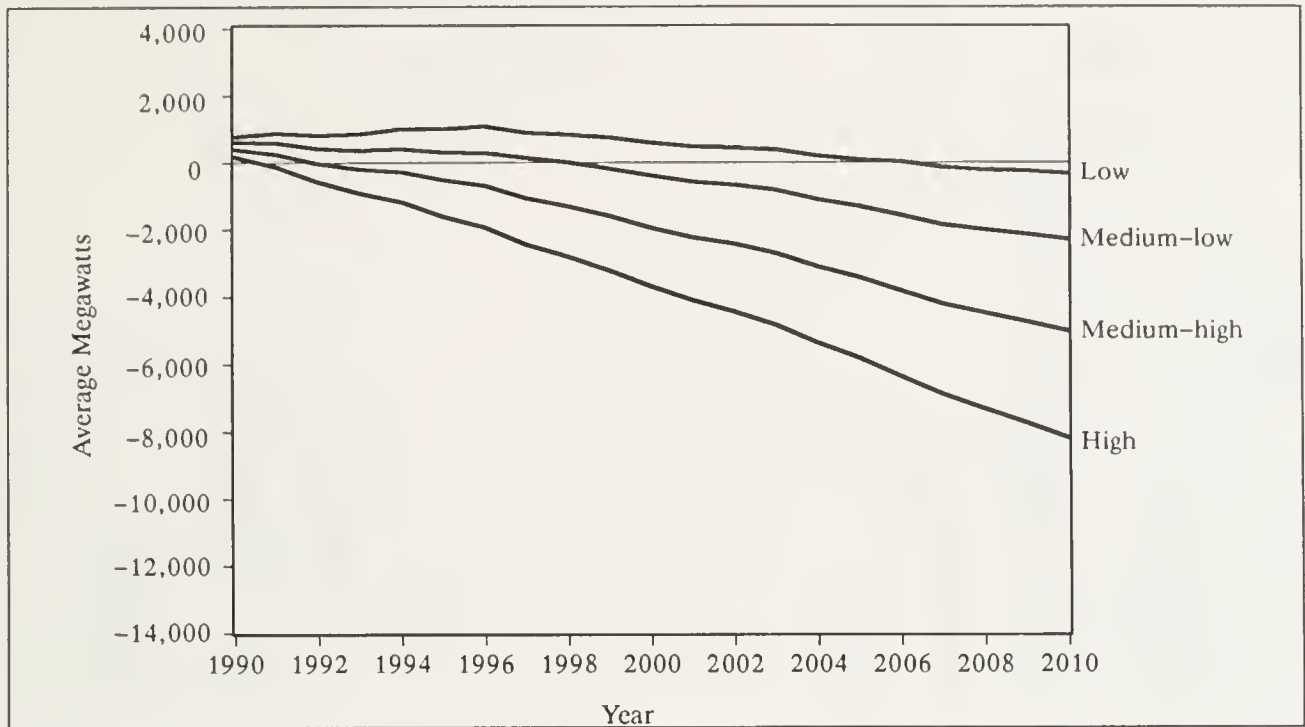


Figure 5-4
Investor-owned Utilities Load/Resource Balance

Resource Availability

To be included in the portfolio, a resource has to be available, reliable and cost-effective, and its environmental impacts must be controllable and acceptable. Previous sections have described the Council's findings on the updated availability and cost of conservation and generating resources. The resource availability described later does not include all of the most recent estimates of resource cost and availability. The Council will refine those estimates during the coming one to two years as it reviews the entire power plan.

Conservation

The Council evaluated conservation opportunities in every sector of the region's economy. The evaluation began by identifying individual conservation measures that could improve the efficiency of electricity production or consumption. The

Council evaluated each individual measure separately as well as in combination with other individual measures.

Figure 5-5 illustrates the conservation savings the Council estimates are available in each of the four load scenarios. This figure shows that the Council has identified 13 individual conservation program areas that in the high case can save 2,540 megawatts. The average cost of all conservation is 2.4 cents per kilowatt-hour. The portfolio includes programs in the residential sector (including more efficient appliances and manufactured homes), commercial, governmental, industrial and agricultural sectors. The portfolio only includes 34 megawatts of improvements to the efficiency of the regional transmission and distribution system. More recent estimates have shown that this could go up to about 500 megawatts, but additional study and discussion is needed with the

region's utilities to verify these estimates.

Resources identified to meet the region's needs under each of the four load-growth scenarios are shown in Table 5-1. Many of the conservation programs save varying amounts of energy depending on the amount of load-growth forecast. This effect is most apparent in non-discretionary conservation programs whose savings are driven primarily by the level of new-building development in the region. Because base economic growth assumptions feed into the electrical load forecast in each scenario, the number of buildings developed in each scenario is substantially different. As more buildings are constructed in higher-load scenarios, there are obviously more opportunities to conserve through the acquisition of lost-opportunity conservation measures.

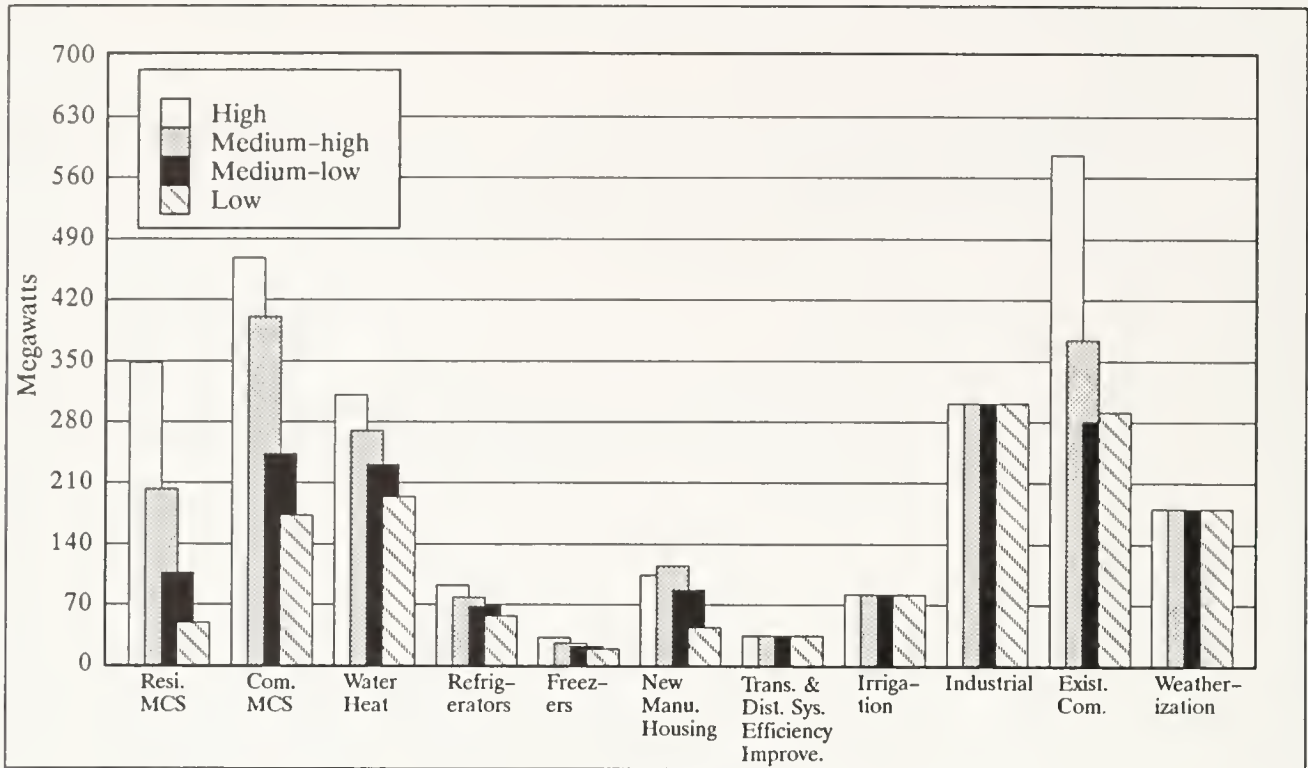


Figure 5-5
Conservation Availability

The conservation estimates shown in Table 5-1 for each of the 13 programmatic areas are based on supply curves for individual conservation measures that assume approximately an 85-percent penetration rate as the practical limit for savings in each program area. When these conservation programs are evaluated, the Council includes the total societal costs of purchasing and installing the equipment necessary to achieve the efficiency improvements. It also assumes that program overhead costs are about 20 percent of the total direct costs to install the conservation measures.

In addition to the achievable levels of conservation in each program area, the

timing and flexibility of each discretionary conservation program are controlled through the conservation assumptions. These assumptions are used to simulate the introduction of conservation programs in the future. The estimates shown in Table 5-2 are used in the analysis as performance parameters for each conservation program.

In the Council's portfolio studies, the penetration of conservation programs is modeled much like the performance of an automobile. There are estimates of how quickly each program can accelerate or increase the rate it achieves conservation savings. Similarly, each conservation program has a maximum speed or a

maximum rate at which it acquires conservation savings each year. Like an automobile, conservation programs may need to be slowed if loads fail to grow as originally forecast. Therefore, the Council uses an assumed maximum braking rate that controls the rate at which any conservation program can be slowed to more closely match the needs of actual load growth. But, conservation programs may not be able to be started and stopped without losing some energy savings. For this reason, the Council assumes that there is a minimum viable level that maintains any given program's ability to be accelerated if future load growth requires additional savings.

Table 5-1
Regional Resource Availability
(Average Megawatts)

	LOAD SCENARIO			
	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
<u>Conservation Program</u>				
Single-family Residential MCS	311	169	78	29
Multifamily Residential MCS	37	34	29	20
Commercial MCS	468	400	243	173
Water Heat	311	270	231	194
Refrigerators	92	78	68	57
Freezers	32	25	22	19
New Manufactured Housing	104	115	87	44
T&D Efficiency Improvements	34	34	34	34
Irrigation	82	82	82	82
Industrial	301	301	301	301
Existing Commercial	586	374	281	291
Single-family Weatherization	135	135	135	135
Multifamily Weatherization	46	46	46	46
<u>Generating Resources</u>				
Hydro Efficiency Improvements	110	110	110	110
New Hydro 1	90	90	90	90
Nonfirm	688	688	688	688
New Hydro 2	105	105	105	105
Cogeneration	320	190	190	130
New Hydro 3	125	125	125	125
Licensed Coal	905	905	905	905
New Coal	4,520	4,520	4,520	4,520
Resources Under Review	4,520	4,520	4,520	4,520

Table 5-2
Conservation Program Assumptions

	MINIMUM VIABLE (%/year)	MAXIMUM ACCELERATION (%/year/year)	MAXIMUM DECELERATION (%/year/year)	MAXIMUM RATE (%/year)
Existing Residential Space Heat	2	7	7	15
Existing Commercial	2	2	2	8
Existing Industrial	0	2	3	8
Agriculture	0	2	3	8
Transmission and Distribution	0	6	15	15

Table 5-2 shows the assumptions used to model discretionary conservation programs. If there were no ramping up or down of programs, and the programs were operated at full levels, the maximum rate would determine how long it took to secure the entire amount of the resource. For example, in the existing residential space-heating sector, the

maximum rate is 15 percent per year. This implies about seven years to secure 100 percent of the resource. However, since the program would have to accelerate to reach this level, and acceleration is constrained to happen at only 7 percent per year, it would take about two years to come up to full speed. The existing commercial, industrial and agricultural sectors have the longest lead times. Starting from zero, it would take four years to get to the maximum rate of 8 percent, the remaining conservation would take a little more than eight years if the maximum rate were maintained.

Other than the residential space-heating sector, which indicates that much quicker rates could be used than in the industrial and commercial sectors, there is little experience with how quickly programs really can secure the total conservation resource identified in this update.

For non-discretionary conservation resources, or those that most typically are secured in new buildings and new appliances, the speed of acquisition depends on the forecast. If growth rates are high, then significant amounts of conservation can be secured as new buildings are built and new appliances purchased. However, if growth rates are low, little conservation is secured.

Available generating resources are also shown in Table 5-1. These resources include new hydropower. New hydroelectric generation was analyzed in four separate blocks that group resources with similar economic characteristics. "New Hydro 1" is the lowest cost, and "New Hydro 4" is the highest cost. New Hydro 4 was not found to be cost-effective and is not shown in Table 5-1. These estimates have been revised since the 1986 Power Plan based on the Council's protected areas policy and new information in the hydropower data base. Estimates of the availability of cost-effective strategies for making better use of non-firm hydropower have not been updated

in this supplement. While studies have shown that substantial increases in the amounts of cost-effective nonfirm strategies may be justified, this issue needs additional analysis and discussion. Similarly, cogeneration and coal-fired power plant availabilities remain unchanged from the 1986 plan.

In many of the Council's estimated paths of future load growth, the amount of power available from conservation, new hydropower, nonfirm strategies, cogeneration, and coal is not sufficient to meet the region's needs over the next 20 years. In these growth scenarios additional resources that could be provided from many different resource alternatives are needed. For this reason, Table 5-1 shows the amount of power from new resources that is needed to fulfill the requirements of the high load growth scenario. For the purposes of the Council's resource portfolio, this resource is modeled with costs similar to a conventional pulverized coal plant. The Council is beginning additional analysis, research and discussion in the hope that new resources can be identified that are more cost-effective and environmentally benign than new coal plants.

In developing its power plan, the Council used an integrated system for analysis of resource acquisitions that is based on decision analysis methods. This approach explicitly models the costs of many different resource decisions under hundreds of possible load growth paths. This model was developed in cooperation with Bonneville and the Intercompany Pool, an association of investor-owned utilities.

Bonneville's Resource Portfolio

The Northwest Power Act requires the Council to develop a regional electric power plan. As part of this regional plan, the Act requires the Council to plan resources to reduce or meet the Bonneville Administrator's load obligations and re-

quires Bonneville to acquire resources needed to meet its contractual obligations. Because it is unlikely that all utilities will choose to place all their future load growth on Bonneville, this plan recognizes that the obligations of Bonneville will be less than the entire region's load growth.

In developing this power plan, the Council focused on the needs of the Administrator's current customers, the collective needs of the region and the needs of the investor-owned utilities as a group. Future loads of current Bonneville firm-power customers, primarily public utilities and direct service industries, are substantially uncertain. The total range of load uncertainty for Bonneville, even assuming no additional loads from customers other than the public utilities, is greater than 4,800 megawatts by 2010. This range of uncertainty could be larger if public utilities continue to develop new resources instead of remaining customers of Bonneville. That uncertainty also could grow if some direct service industries operate at less than current plant capacity or if they do not renew their contracts in 2001.

The Administrator's contractual obligations (potentially including investor-owned utility load growth) give the Administrator a range of uncertainty of 13,500 megawatts by the year 2010. This substantial uncertainty poses a particular dilemma to the Council and Bonneville. This dilemma is whether to undertake actions that prepare Bonneville to meet all the Administrator's obligations, even though the cost of these actions may be difficult to allocate fairly to all customers. The question of cost allocation to Bonneville's customers is best addressed in Bonneville rate cases. For this reason, the Council has identified necessary and cost-effective actions that can help the Administrator meet Bonneville's contractual obligations at the lowest possible cost. Bonneville should undertake these activities to ensure that it is the low-cost

provider envisioned by Congress and the region in the Northwest Power Act. In developing its power plan, the Council sought to strike an appropriate balance between the risk represented by uncertainty in the Administrator's obligations, and the near-term cost to Bonneville's customers of securing sufficient options to manage this uncertainty effectively.

Balancing Bonneville's uncertainty and the cost of insurance, the Council follows a two-step planning strategy. The first step calls for Bonneville to lead the region in developing the capability to secure conservation savings and to develop and maintain options on resources so that the Administrator can meet rapid load growth. This strategy recognizes the importance of securing options to meet high levels of load growth, since the cost of options is small compared with having too few or too many resources. At the same time, the Council expects that Bonneville will not be responsible for securing all options, since some utilities will undertake independent actions. It is important to note again that securing resource options and developing conservation capability does not necessarily mean that resources will be developed.

The second step identifies the resources Bonneville should acquire. Because Bonneville faces considerable uncertainty with respect to future investor-owned utility loads, the plan expects Bonneville to build and acquire sufficient new resources to achieve the lowest expected cost for Bonneville's current firm power customers. The plan recognizes that even the loads of Bonneville's customers are quite uncertain. However, the costs of resources acquired today are likely to be borne only by Bonneville's current customers. Accordingly, this strategy will help minimize Bonneville's cost of serving its customers and, thereby, help hold down the cost of electric energy services to Bonneville's customers.

Schedule for Acquiring Resources to Meet Bonneville's Current Customers

Figure 5-6 illustrates the overall schedule of resource acquisition for Bonneville if it continues to serve only current customers and if those customers do not develop substantial new resources in lieu of purchasing from Bonneville. In the highest-load forecast, Bonneville begins acquiring discretionary conservation immediately. In the medium-high, Bonneville begins discretionary conservation programs in 1994; in the medium-low, discretionary conservation is not needed until late in the planning period.

Figure 5-6 illustrates that if Bonneville experiences high load growth, it would achieve approximately 800 megawatts of savings from all conservation programs by the end of the planning period. In addition to this conservation, Bonneville could add 75 megawatts of available system efficiency improvements, 459 megawatts of simple-cycle combustion turbines, 18 megawatts of new hydropower and 1,800 megawatts of coal-fired power plants.

The resources identified in this supplement are not sufficient to meet the needs of the Bonneville Administrator if high load growth occurs. To meet the needs of Bonneville's current customers, an additional 1,350 megawatts of resources that are currently under review need to be added to the resource portfolio. The first of these new resources is needed in 1998. To meet the Administrator's needs in the high, about half of the new resources that need to be identified must have a lead time of eight years or less.

Following the adoption of this supplement, the Council will begin to review a wide variety of additional conservation and generating resource alternatives. Both coal-fired power plants and the resources labeled as "resources under re-

view" will be the subject of intensive analysis, research and Council decision making. These follow-up studies are designed to identify additional resources that are both cost-effective, more environmentally benign and have short lead times. In spite of this research, substantial amounts of new resources will probably not be known until private, independent parties bring forward resources with characteristics that are competitive with the resources included in the portfolio.

In the 1986 Power Plan, the Council called on Bonneville to develop a policy to guide the acquisition of new resources. Such a policy will help identify mechanisms, such as bidding schemes, that will encourage an open competition among new resources to meet the region's needs. Through bidding, the region should be able to identify substantial amounts of resources that are cost-effective and environmentally competitive with new coal plants.

Figure 5-6 also shows that, for the medium-high, Bonneville will need to add 660 megawatts of conservation, 75 megawatts of available hydropower efficiency improvements, 459 megawatts of simple-cycle combustion turbines and 900 megawatts of coal-fired power plants. If loads between the medium-low or low load growth occur, Bonneville does not need resources beyond the lost-opportunity conservation programs, because the agency is surplus until beyond 2010.

The Role of Nonfirm Strategies

Significant questions have been raised concerning alternative strategies for better use of the existing hydropower system. These strategies are frequently referred to as "nonfirm strategies," since they rely primarily on techniques that will allow the region to better use what is called nonfirm hydroelectric power. Fig-

ure 5-7 shows a seasonal hydropower duration curve. This figure illustrates the percent of time that varying amounts of hydro-generated energy is available. The horizontal scale is measured in average seasonal megawatts. The seasons vary from three to four months, with May being a separate season due to water budget flows. The figure illustrates that firm energy load carrying capability (FELCC) or firm energy, is currently about 12,300 megawatts. This is the level of hydro system output that would occur if the region experienced a repeat of the four driest years on record, 1928 to 1932. This four-year sequence of poor water, known as the critical water period, generates the least firm energy of any historical sequence of water conditions since record-keeping began in 1879.

There is approximately a 2 percent to 3 percent probability that worse than critical water conditions could develop. However, in most water years, substantially more energy is produced by the region's hydroelectric system. Energy that is produced in excess of the firm energy load carrying capability of the system is called nonfirm energy. This nonfirm energy serves a variety of customers both in the region and in California. These customers include the direct service industries (service for the top quartile), generating utilities in the region (displacement of thermal resources), and California utilities (displacement of other purchases and thermal generation). This curve illustrates that the difference between the amount of energy available at critical water and the amount of energy we would expect to be available at

least 50 percent of the time is approximately 6,000 megawatts per season.

The Council has been searching for alternative mechanisms that would make better use of this nonfirm hydro energy. While maintaining the current reliability provided by planning to critical water, the Council has considered employing combustion turbines to back up the variability in the existing hydro system, shown in Figure 5-7. Using the estimates of the cost and performance of new combustion turbines and the natural gas price forecasts contained in the supplement, as much as 3,000 megawatts of nonfirm strategies could be cost-effective. Other strategies could possibly perform better than new combustion turbines. This needs to be studied further.

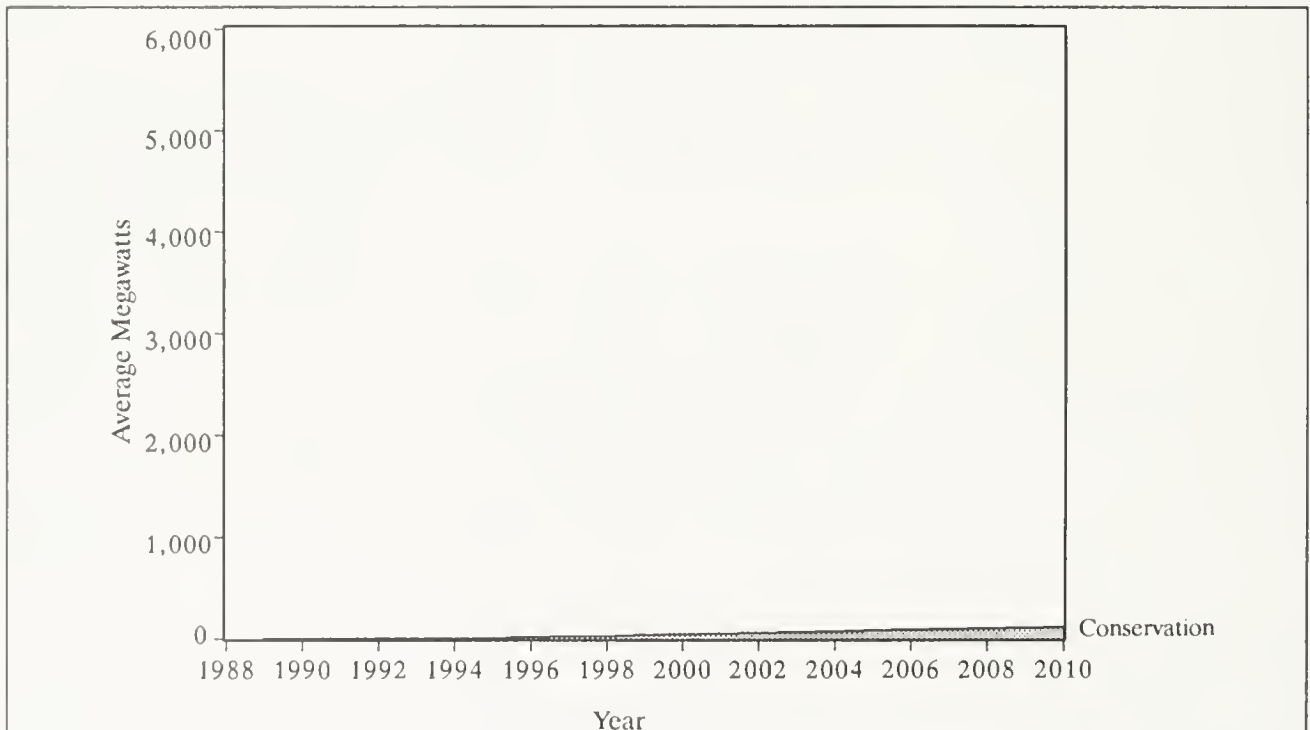


Figure 5-6
Bonneville Resource Additions (Low)



Figure 5-6 (cont.)
Bonneville Resource Additions (Medium-low)

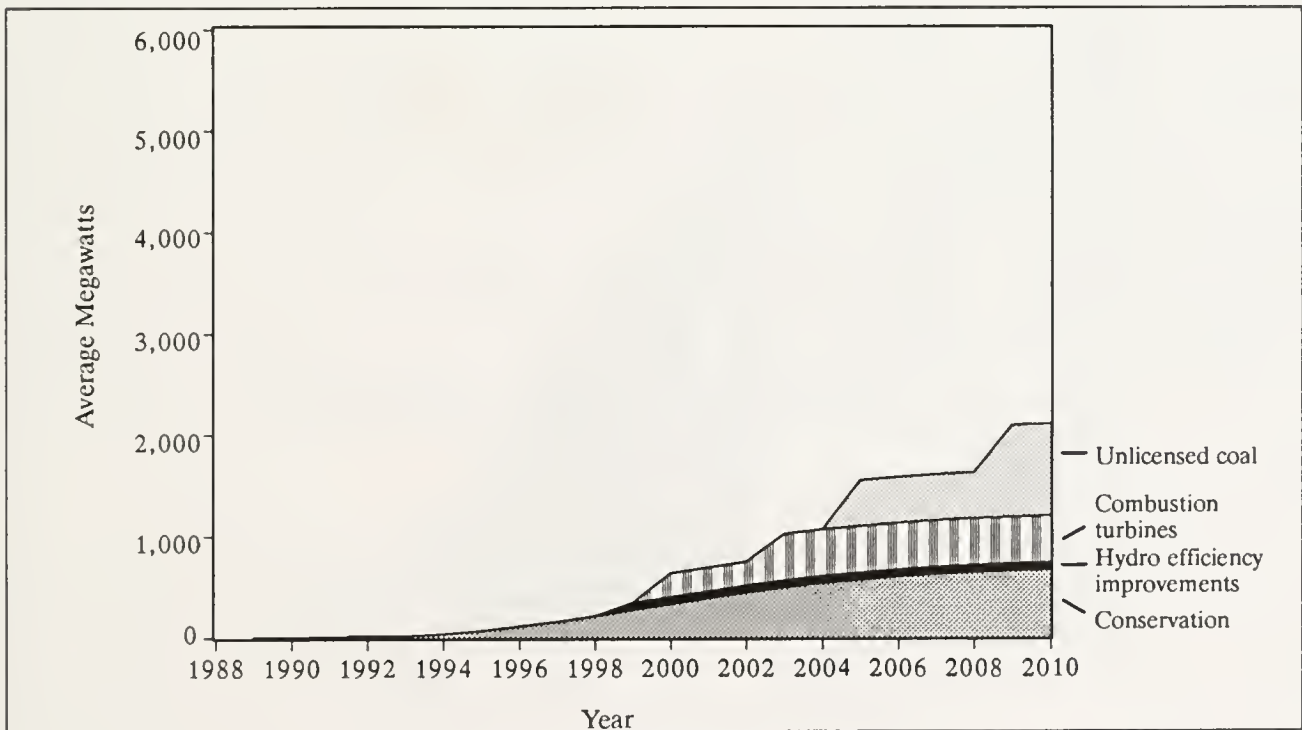


Figure 5-6 (cont.)
Bonneville Resource Additions (Medium-high)

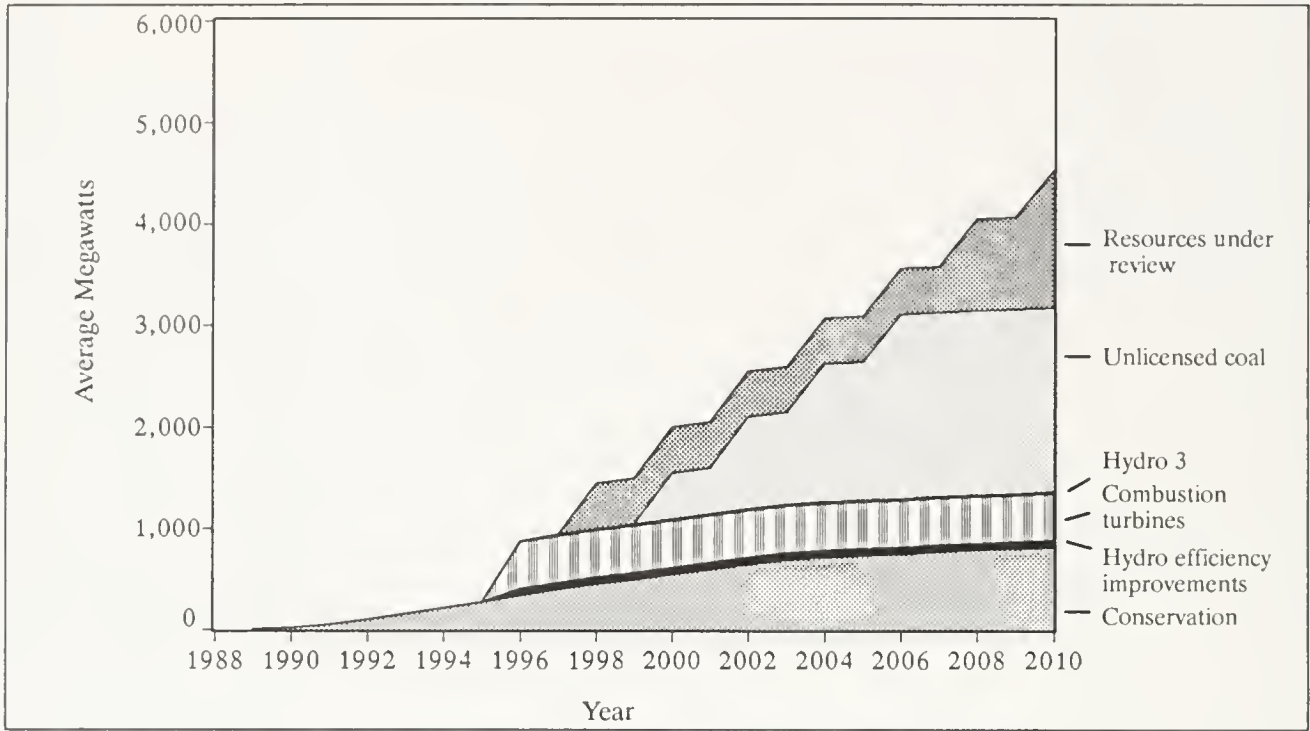


Figure 5-6 (cont.)
Bonneville Resource Additions (High)

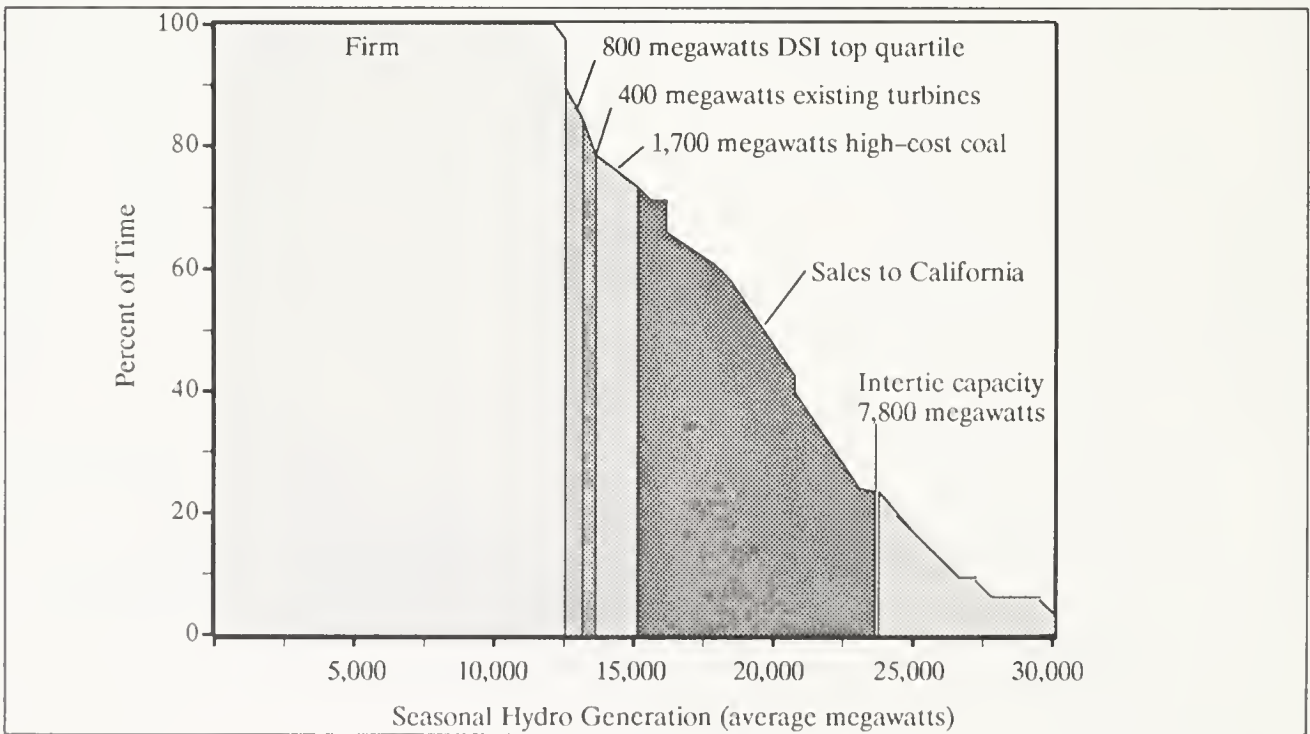


Figure 5-7
Hydro Duration Curve

The Region's Resource Portfolio

While the Administrator's obligations are a fundamental part of the Council's plan, the Council must also look at the region as a whole to ensure that the plan is not unknowingly developing barriers to achieving a low-cost electric energy future for all the citizens of the Northwest. The resource portfolio for a coordinated Northwest power system can help the Council establish energy policies that transcend current utility conditions.

The resource requirements for the Pacific Northwest in each of the four primary load scenarios were shown in Figure 5-2. Although no one knows how the region actually will grow, Figure 5-8 shows resources that would be needed to meet the requirements of each of the four basic load scenarios. In developing the resource portfolio, the Council assumes that the region's utilities coordinate resource acquisitions to secure the lowest-cost resources first. This level of cooperation is unprecedented in the region, since resources available to some utilities are developed earlier than needed by those utilities to serve the needs of others. Through this level of cooperation, the region's utilities could substantially reduce the future cost of electricity.

The four resource schedules shown in Figure 5-8 identify actions that the region may have to take in the future if any one of the four load scenarios materializes. The future resource acquisitions

shown in the high scenario are not likely to occur, since load and resource conditions could change as the future unfolds. However, based on current knowledge, these resource schedules show the actions the region should take to achieve the lowest-cost electricity if loads grow as forecast in the Council's four primary load scenarios.

The high load scenario has regional loads growing quickly enough to consume the current surplus by about 1992. All of the major conservation programs would start immediately and achieve a total savings of 2,540 megawatts by 2010. As the conservation programs are running, the region begins in 1994 to bring on line hydropower system efficiency improvements that ultimately achieve 110 megawatts. Strategies to better use nonfirm begin in 1993, which result in the addition of 690 megawatts of new combustion turbines by 1996. Beginning in 1995, the high load case would require the region to acquire the available new small hydropower, approximately 400 megawatts in total. Cogeneration resources would need to be acquired beginning in 1993, with 320 megawatts available. To meet the needs of the high load scenario, the Council needs to identify 900 megawatts of additional resources that have lead times of five years or less. The Council is currently researching several additional resource alternatives that are not included in this supplement. For this reason, these resources are labeled resources under review. In addition, another 450 megawatts of resources that

have yet to be identified are needed with an eight-year or less lead time. In total, the Council needs to identify 4,500 megawatts of additional resources from the list of resource alternatives that is currently under review. In 1996 and 1997, the two licensed coal plants that are available in the region are needed. New unlicensed coal-fired power plants are added first in 1999, and by 2010 a total of 12 coal plants with 5,400 megawatts of energy generation are added.

The availability of these coal-fired plants is currently under discussion and analysis by the Council. Significant environmental concerns exist regarding the impact on air quality, water quality and land use from roughly doubling the region's reliance on coal-fired energy. The Council plans to encourage an open competition among all potentially cost-effective resource suppliers. If sufficient new resources can be identified, these coal plants could be avoided or they could be held as options and their construction delayed.

More research and discussion will be necessary before a consensus can form as to what additional resources should be in the portfolio. Over the next two years, the Council will examine the cost and availability of a wide variety of new resources that could help the region meet rapid load growth. Time is of the essence. To be able to cover high load growth, the region could need to make major commitments to new resources almost immediately.

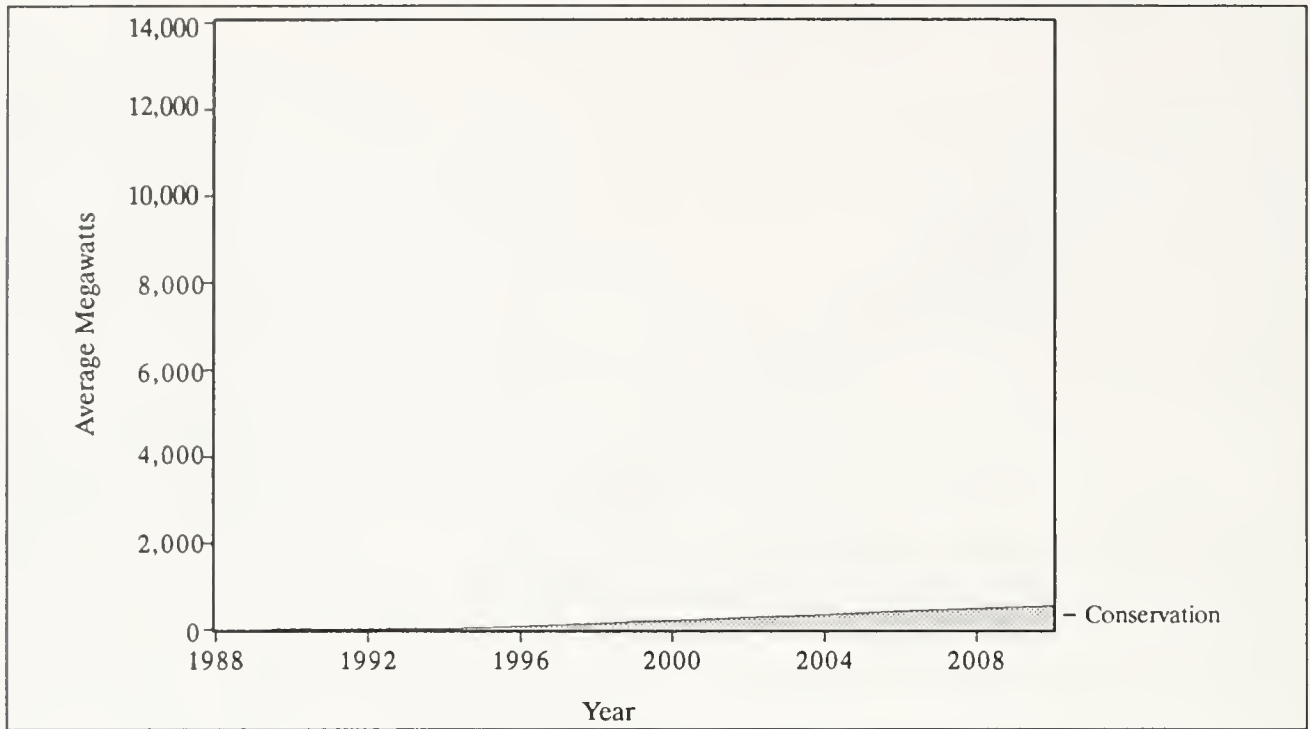


Figure 5-8
Regional Resource Additions (Low)

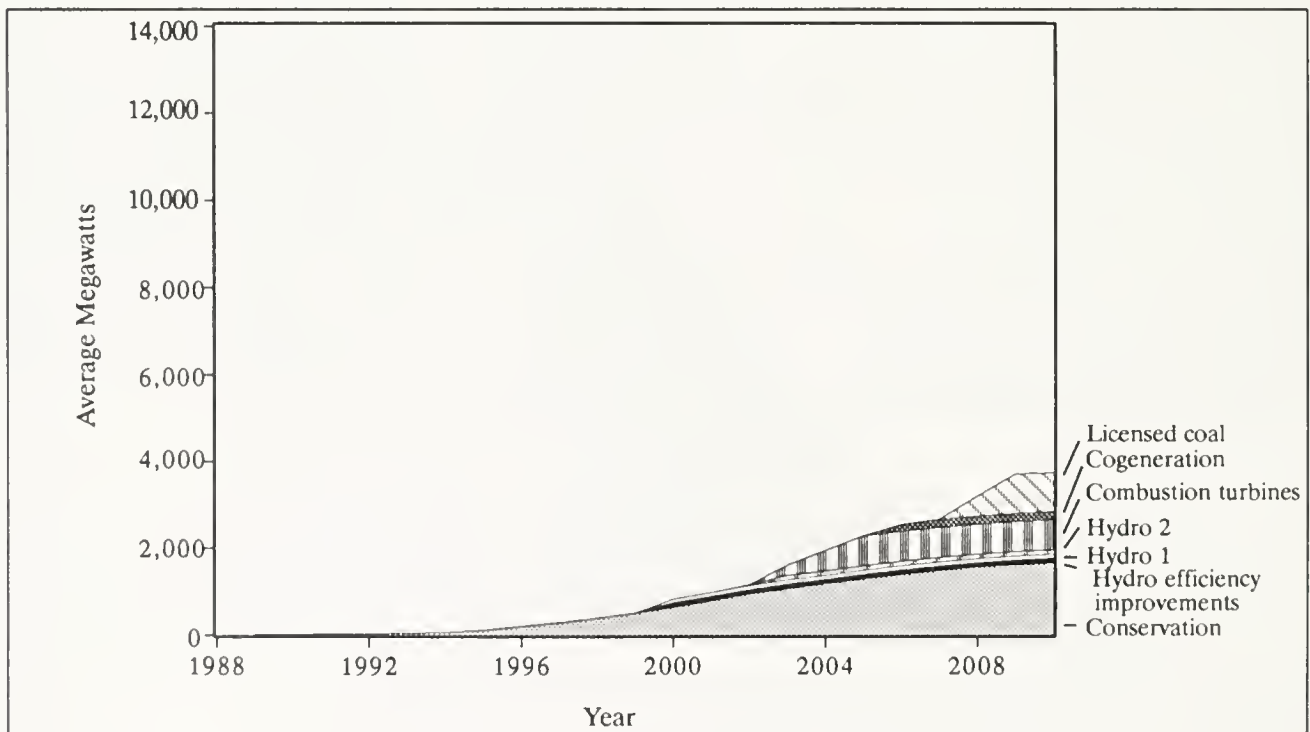


Figure 5-8 (cont.)
Regional Resource Additions (Medium-low)

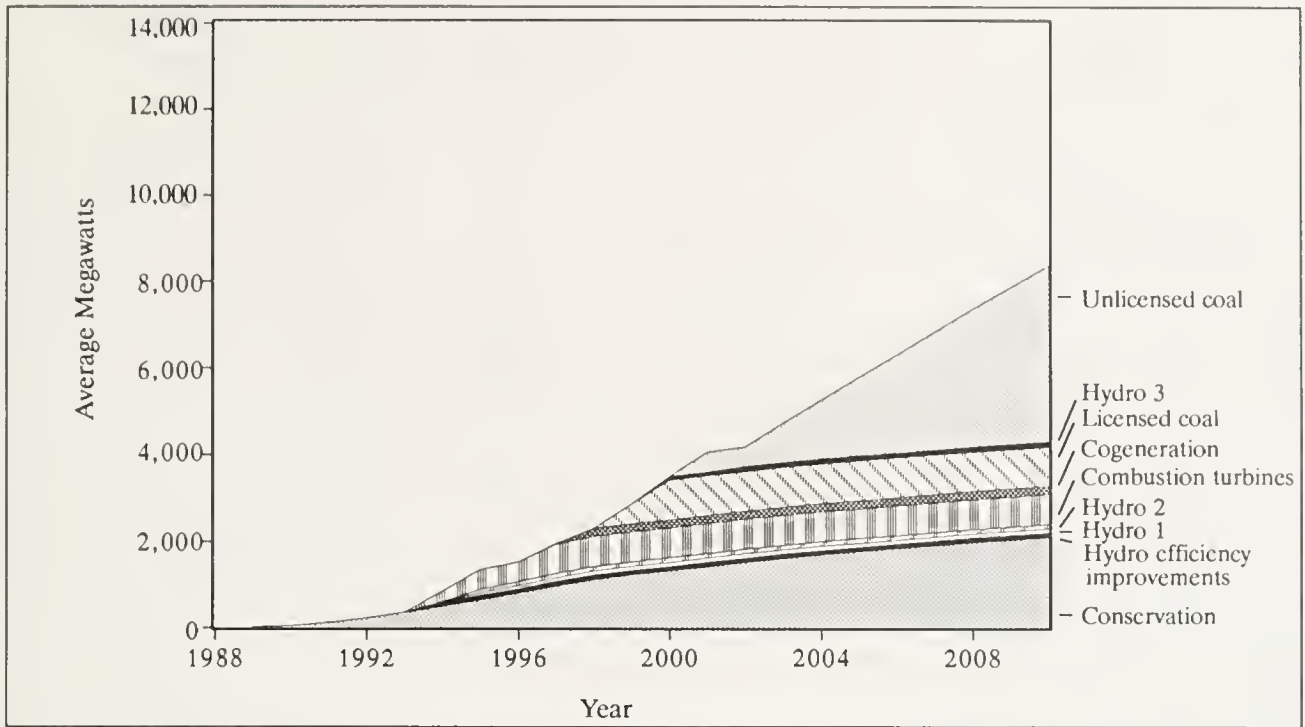


Figure 5-8 (cont.)
Regional Resource Additions (Medium-high)

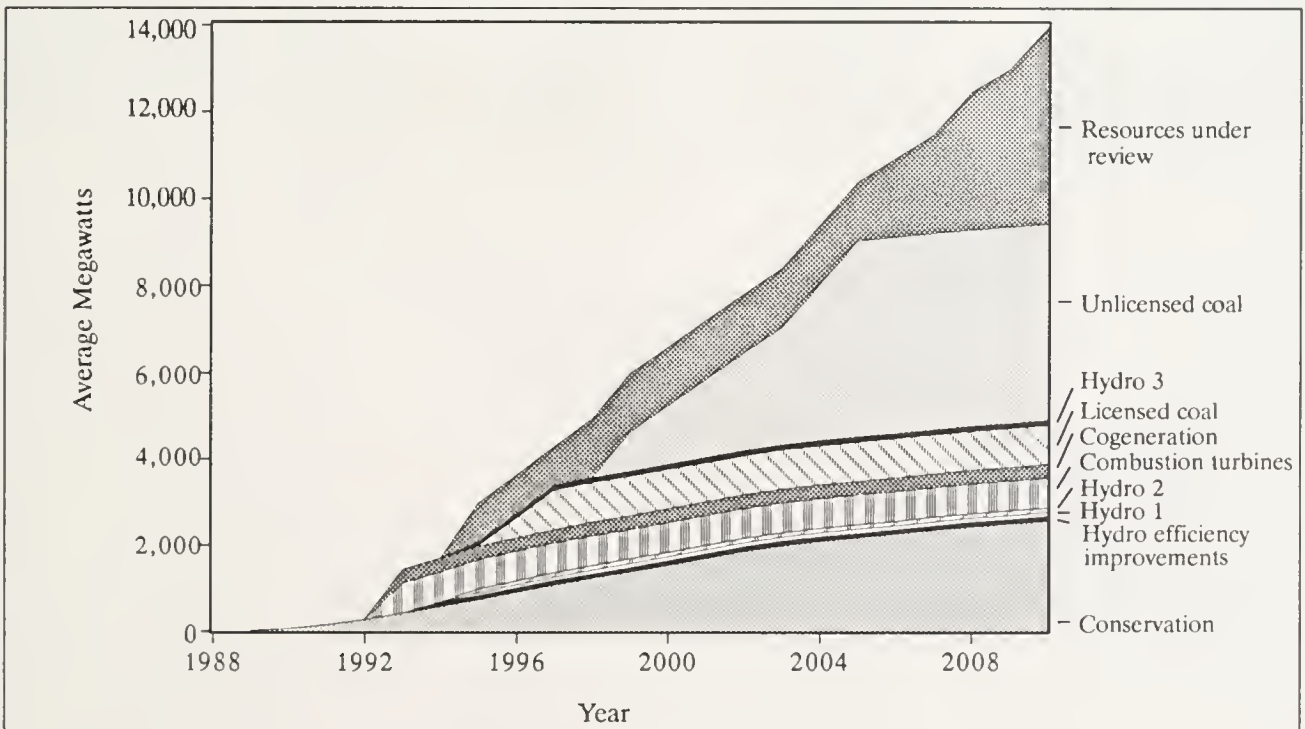


Figure 5-8 (cont.)
Regional Resource Additions (High)

Similar types of resource actions are needed to meet the requirements of the medium-high forecast. The medium-high load scenario shows the region beginning all discretionary conservation programs by 1991. This load scenario anticipates new building activity growing more slowly than in the high case, so only about 2,100 megawatts of conservation would be secured by 2010. Strategies for improving the efficiency of the existing hydropower system and the installation of combustion turbines are needed first in 1994. By 1997, all 690 megawatts of available nonfirm strategies are installed. The region begins to develop the low-cost (New Hydro 1) hydropower and the second block of new hydro in 1995. The requirements of the medium-high scenario have the region acquiring the 189 megawatts of available cogeneration facilities beginning in 1997. In 1999, the first of the licensed coal plants is needed, followed by the second unit in 2000. The needs of the medium-high scenario can be met by adding 11 new coal plants totaling almost 5,000 megawatts of new coal-fired energy.

The medium-low load scenario calls for substantially fewer new resources. The region begins discretionary conservation

programs at a slow pace in 1995. Again, because this load scenario assumes less new construction will take place in the region, the overall conservation opportunity in the medium-low drops to about 1,600 megawatts. The region has all discretionary conservation programs running by 2000. Efficiency improvements in existing hydro facilities and low-cost small hydro are needed first in 2000. The region begins to install new combustion turbines in 2003, and by 2005 approximately 690 megawatts of nonfirm strategies are online. By 2010, about 200 megawatts of small hydropower and 189 megawatts of cogeneration are installed. Two coal plants are needed, one in 2008 and another in 2009, to meet the needs of this scenario.

Finally, if low loads occur, the region is surplus beyond the study period. For this reason, no additional resources are needed, and only the savings that accrue as a result of the region implementing non-discretionary conservation programs are shown. These savings contribute slightly to the regional surplus, but, due to the extremely low rate of new building construction, they add little cost and only 100 megawatts of conservation to the region's resource mix.

Investor-owned Utilities' Resource Portfolio

As a point of comparison, the Council has also analyzed the resource actions that would be undertaken by the investor-owned utilities if they choose not to place loads on Bonneville. This case assumes that the investor-owned utilities do not purchase firm power from Bonneville and that they cooperate to develop the most cost-effective resources to meet their collective needs. Figure 5-9 illustrates the investor-owned utility resource acquisitions as a group in the four load scenarios. These schedules are obviously an aggregate of the actions of six independent companies. No individual company is likely to see a situation like that shown in Figure 5-9. Some will be in better and some in worse conditions from a power supply perspective. Even though there are differences among all utilities in the region, the Council recommends actions that, based on the Council's plan, appear to be prudent for the investor-owned utilities and the public utility commissions to undertake at this time. These recommendations are included in the Action Plan, Chapter 9, in the 1986 Power Plan.

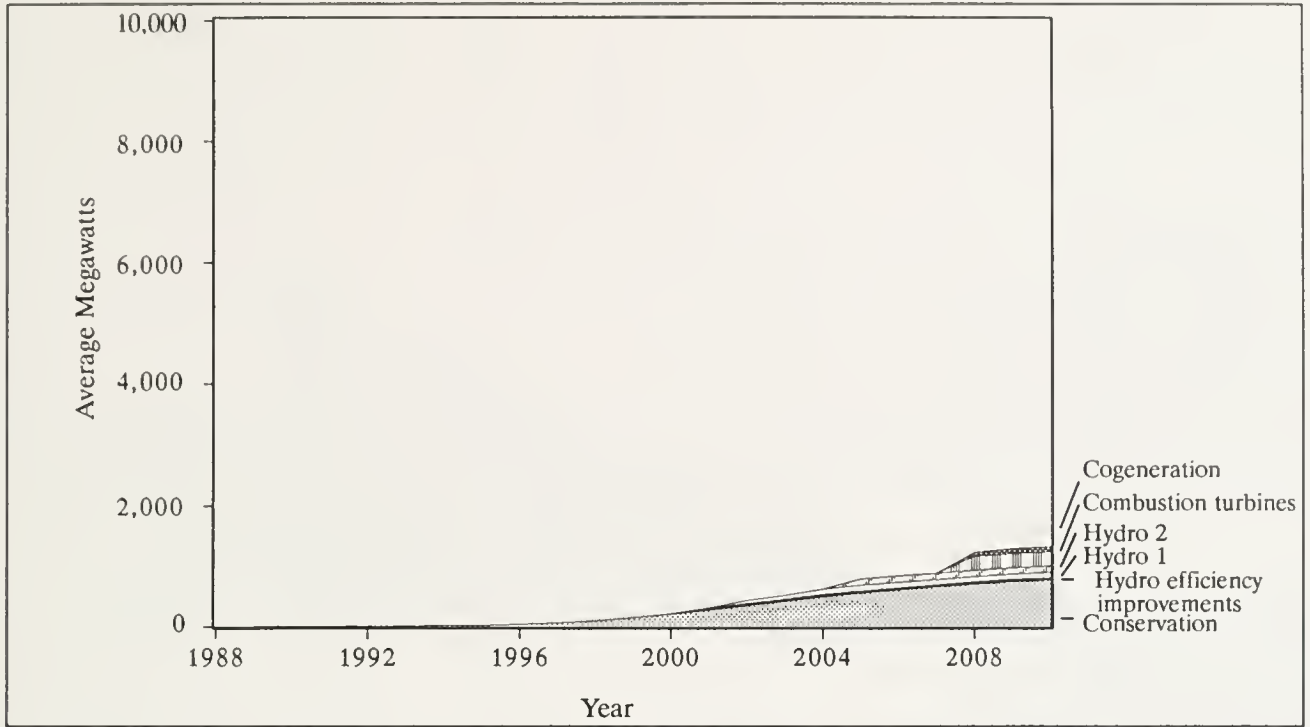


Figure 5-9
Investor-owned Utilities Resource Additions (Low)

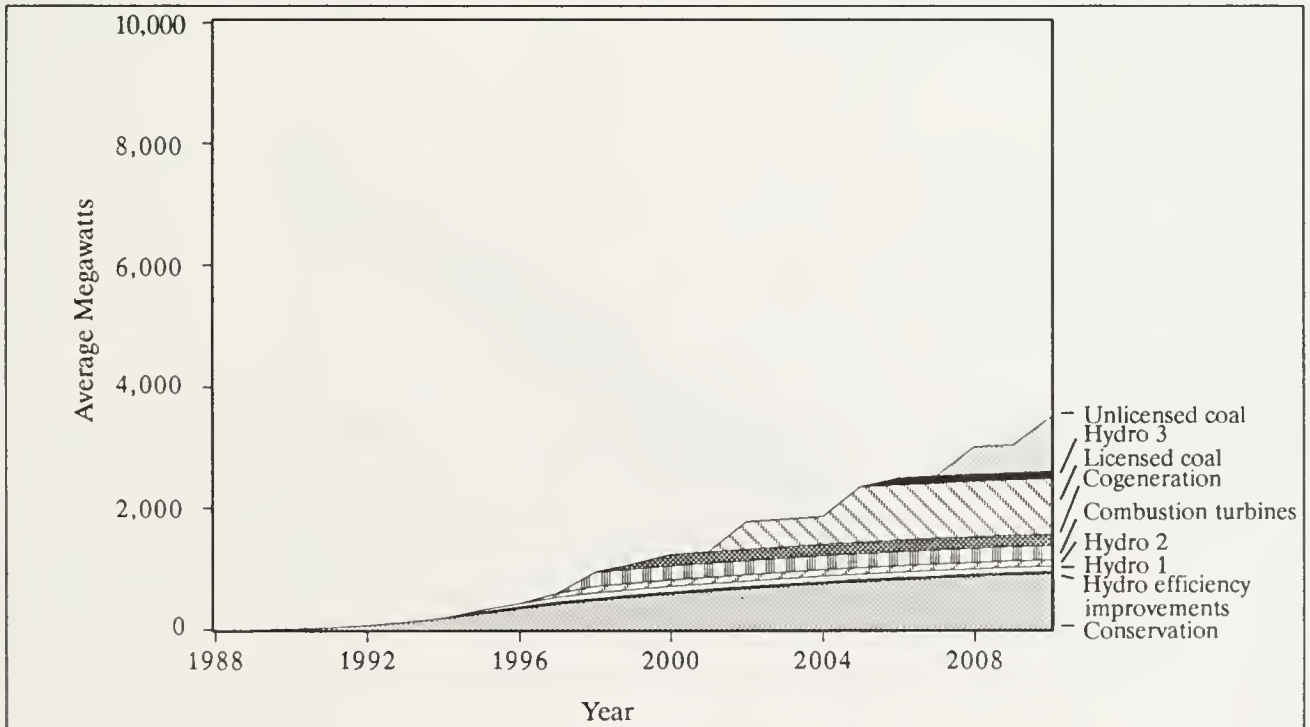


Figure 5-9 (cont.)
Investor-owned Utilities Resource Additions (Medium-low)

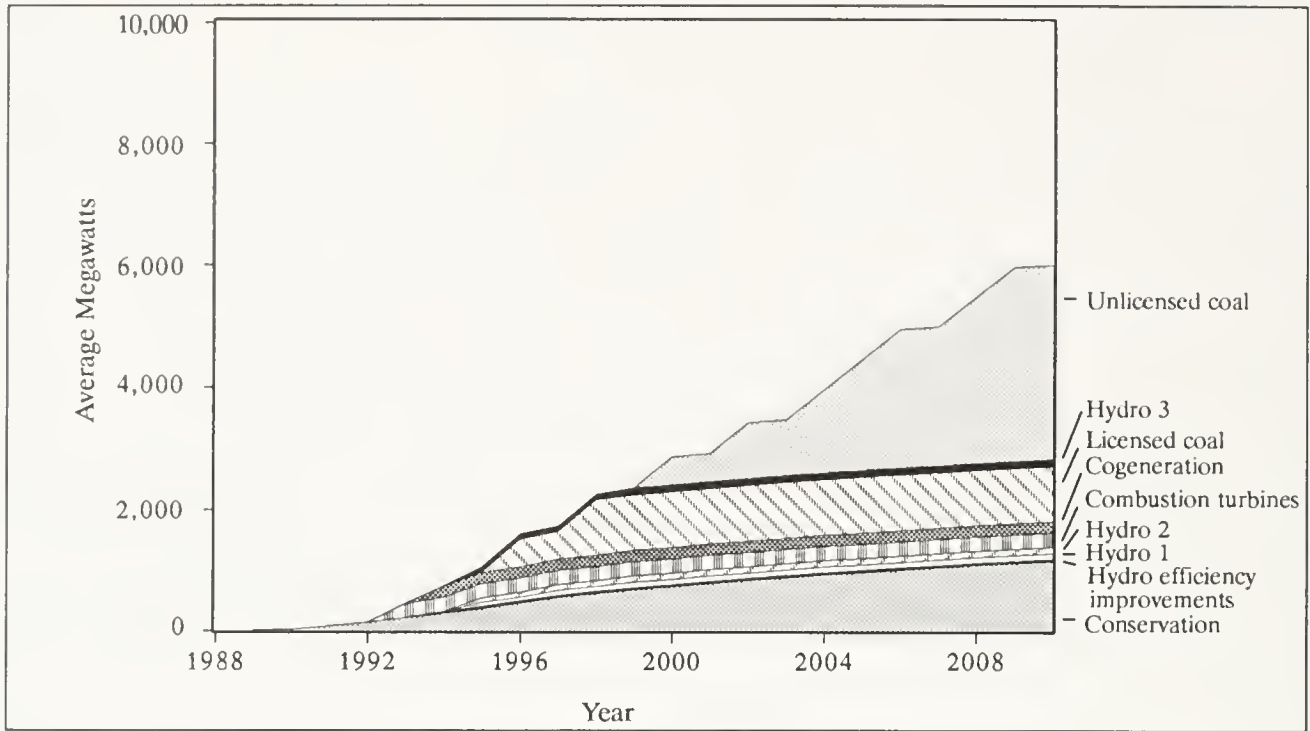


Figure 5-9 (cont.)
Investor-owned Utilities Resource Additions (Medium-high)

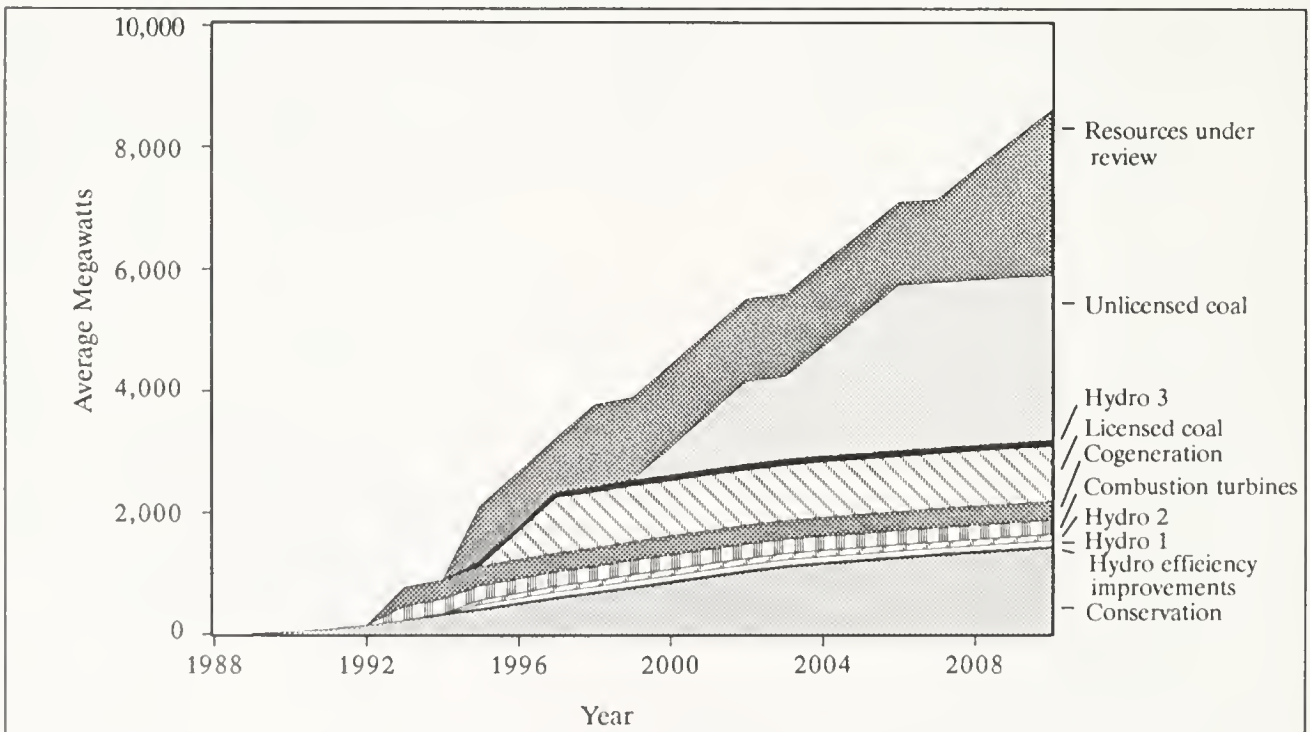


Figure 5-9 (cont.)
Investor-owned Utilities Resource Additions (High)

If the high load scenario occurs and the investor-owned utilities do not place loads on Bonneville, then substantial resource actions are needed to meet their load growth. All discretionary conservation programs would begin as soon as possible in 1990. By 2010, the investor-owned utilities would acquire about 1,400 megawatts of conservation. After initiating conservation programs, the investor-owned utilities as a group would begin to develop nonfirm strategies and cogeneration in 1993. The investor-owned utilities begin to add additional resources that are currently under review in 1995. To meet the investor-owned utilities' needs in high load growth, about 900 megawatts of additional resources with lead times of five years or less need to be identified. If high load growth occurs, the investor-owned utilities would add the first two licensed coal plants in 1996 and 1997 and add a total of 3,600 megawatts of coal-fired energy by 2010. In addition to 900 megawatts of resources with short lead times, the Council needs to identify 1,800 megawatts of new resources that can have up to 10-year lead times to meet the high scenario.

If the medium-high load growth scenario develops, the investor-owned utilities still need to begin to implement all discretionary conservation programs in 1990. The 230 megawatts of available simple-cycle combustion turbines is needed in 1993, and the first cogeneration units begin to appear in the same year. Also, in the mid-1990s, the hydro efficiency improvements and all cost-effective new hydro plants are developed. The highest-cost new hydro begins to be installed in 1995. The medium-high also requires the first licensed coal plant to be added in 1996 with a total of 4,000 megawatts—equal to nine coal-fired units—needed by 2010.

If medium-low loads develop, the investor-owned utilities begin discretionary conservation programs in 1990-1991, and by 1993 all programs would be in operation. These programs effectively meet investor-owned utility load growth until the mid-1990s. Beginning in 1995, however, additional generating resources are needed. These begin with improvements to the existing hydropower system and the lowest-cost new hydropower, followed by the first combustion turbines in 1998. Medium-cost new hydropower is added in 1997, and by 2006 the full 400 megawatts of available new hydropower is in service. New cogeneration resources are acquired beginning in 1999; by 2000, a total of 190 megawatts is installed. If medium-low load growth develops, the investor-owned utilities will need 1,800 megawatts of new coal plants by 2010. The first of these coal plants is needed in 2002.

If the low load scenario develops, investor-owned utilities do not need to begin discretionary conservation programs until the last half of the 1990s. All discretionary conservation programs are gradually started during the period from 1995 through 2002. Improvements to the existing hydropower system are begun in 2001, followed by the acquisition of lowest-cost new hydropower in 2002. The installation of combustion turbines to firm up nonfirm hydropower begins in 2008. By 2010, approximately 200 megawatts of new hydropower are added, along with an additional 230 megawatts of combustion turbines, and 85 megawatts of cogeneration to meet the needs of the low load growth scenario. By 2010, in both discretionary and non-discretionary conservation programs, the investor-owned utilities will have acquired almost 800 megawatts of conservation savings.

Near-term Decisions

The resource portfolio not only determines the schedule for resources to be put online. It also directs when resource option and building decisions are needed to meet that schedule. The Council has extracted from Bonneville's portfolio the resource targets that are necessary to meet the Administrator's resource requirements for current customers. Table 5-3 shows the Administrator's resource acquisitions over the next 10 years in order to meet current customers' loads in the medium-high scenario. The targets for conservation programs are the cumulative energy savings over the next 10 years for each program.

The bottom one-third of the table shows the generating resource options that are needed if medium-high load growth occurs. For each resource, this shows when options should be started and the number of megawatts to be optioned in each year. The megawatts shown are not cumulative. They are the amount of resources for which siting, licensing and design is begun in each year.

Even among Bonneville's current customers there is considerable load uncertainty. If medium-low loads materialize over the next 10 years, Bonneville only develops non-discretionary conservation programs and does not need discretionary conservation or options on new generation.

To illustrate the impact of investor-owned utilities placing loads on Bonneville, Table 5-4 assumes all utilities place their load growth on Bonneville. If this occurs, Bonneville will need to begin all discretionary conservation programs in 1990.

Table 5-3
Resources Needed to Serve Current Bonneville Customers
(Medium-high Forecast in Average Megawatts)

RESOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
<u>Conservation Programs</u> (Cumulative annual energy savings)										
Single-family Residential MCS	1	3	5	7	9	12	14	17	19	21
Multifamily Residential MCS	0	0	1	1	1	2	2	2	2	3
Commercial MCS	0	0	1	2	3	5	8	11	14	17
Water Heat	0	0	0	0	0	0	1	4	8	12
Refrigerators	0	0	0	0	0	0	0	1	2	3
Freezers	0	0	0	0	0	0	0	0	1	1
New Manufactured Housing	0	1	2	3	4	6	7	9	10	11
System Efficiency Improvements	0	0	0	0	1	5	9	14	15	15
Irrigation	0	0	0	0	0	2	4	8	12	16
Industrial	0	0	0	0	0	1	6	13	23	34
Existing Commercial	0	0	0	0	0	4	16	33	50	67
Single-family Weatherization	0	0	0	0	0	0	0	0	1	7
Multifamily Weatherization	0	0	0	0	0	0	0	0	0	1
<u>New Generation Options</u> (Non-cumulative energy)										
Hydropower Efficiency Improvements	0	0	0	0	0	75	0	0	0	0
New Hydro 1	0	0	0	0	0	0	0	0	0	0
Simple-cycle Combustion Turbine	0	0	0	0	0	0	0	230	0	0
New Hydro 2	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
New Hydro 3	0	0	0	0	0	0	0	0	0	0
Coal Plants	0	0	0	0	0	0	452	0	0	452

To meet the needs of medium-high growth with investor-owned utilities, Bonneville would need to option hydropower efficiency improvements, small hydropower, nonfirm strategies and new resources in 1989. Simple-cycle combustion turbines are optioned in 230-megawatt sizes at one site. Combustion turbine options begin in 1989, with three plants optioned by 1991. Following the simple-cycle combustion turbines, 107 megawatts of medium-cost small hydropower options are secured in 1990. Comparing Table 5-4 with Table 5-3 illustrates the significant increase in conservation and generation activity if Bonneville's obligations expand to include all the region's utilities.

The federal government requires Bonneville's budget planning to be done up to seven years in advance of actual ex-

penditures. No one knows how loads will grow over the next seven to 10 years; however, the Council believes that Bonneville should build the capability to implement conservation programs that can meet the needs of the medium-high load scenario for Bonneville's current customers. Bonneville should use Table 5-3 as a guide for setting conservation budgets and targets. The Council has selected medium-high loads for conservation capability building so that Bonneville will be prepared to meet the requirements of its current customers for the most likely range of load growth. If loads grow slowly, however, capability should be built and then maintained, and very little actual resource acquisition should occur.

Tables 5-3 and 5-4 show the range of resource options needed by Bonneville un-

der medium-high load growth with either current customers or all utilities. The contrast is dramatic. If all utilities plan to place new loads on Bonneville, the Administrator needs a significant amount of options over the next 10 years. However, since at this time only the public utilities have placed firm loads on Bonneville, the agency needs only 1,400 megawatts of generating options over the next 10 years to meet the requirements of current customers and medium-high load growth.

This uncertainty in the plans of investor-owned utilities makes it particularly difficult for the Council to map out a least-cost plan for the region as a whole. Coordinated planning indicates a significant amount of action is needed over the next few years if medium-high or higher load growth occurs. Because of this, it

appears prudent for the Administrator to continue with capability building and acquisition of all cost-effective lost opportunities. This will help to meet the Administrator's current obligations and future load from utilities that are currently not purchasing firm power from Bonneville. Failure to prepare could expose all of Bonneville's customers to the risk of the region not being able to meet load or having to make emergency purchases at high costs.

On the other side of this dilemma is the question of who should pay for preparing to meet future load. If Bonneville invests in building the capability to deliver conservation savings and securing options as insurance against load uncertainties, it is difficult to determine exactly whom the insurance policy will benefit. Everyone agrees that those who benefit should pay, but how should Bonneville and the Council determine the specific utilities that will benefit from the Administrator having capability to acquire conservation and flexibility through options? Capability to secure conservation and developing options could benefit any entity in the region that needs to turn to Bonneville as a low-cost supplier of wholesale power.

The Council will monitor Bonneville's actual loads over the next several years, but it is clear that the resource portfolio analysis indicates that Bonneville should be budgeting to develop the capability to acquire conservation in every sector and to secure and maintain an option inven-

tory before the current surplus is exhausted.

Establishing conservation budgets involves estimating the necessary resources for both capability building (test and pilot) projects and the costs associated with acquisition programs. Because the future load growth for Bonneville is uncertain, it is not possible to provide a fixed budget for conservation over seven to 10 years. Nevertheless, budgets must be established. To assist utilities with budgeting, Figure 5-10 shows the annual expenditures for all conservation acquisition programs included in the resource portfolio, assuming medium-high loads occur. Obviously, it would be imprudent to acquire the conservation needed in the medium-high if less than medium-high loads develop. On the other hand, it is prudent to have the capabilities, including staffing and budget, to meet medium-high growth rates if they materialize. Also, these estimated expenditures include the total cost to purchase and install all measures. It is likely that acquisition programs can be designed to achieve high penetration rates with lower financial assistance than Figure 5-10 shows.

The region currently has initiated siting and licensing for several thermal resources. The Creston coal plants are a notable example of resource options that help insure against significant increases in load growth. These sites could be lost if not properly maintained. Bonneville

also needs to develop experience with the legal, institutional and financial issues surrounding securing and maintaining options. For this reason, and because an option could be low cost if secured at this time, Bonneville should continue to work with resource developers to maintain the current options as long as possible.

It is not possible for the Council to know exactly the Administrator's load obligations over the next 10 years. Substantial uncertainties remain with respect to the basic level of load growth, the amount and timing of investor-owned utility loads that might be placed on Bonneville, the availability in the future of additional resources not included in this plan, and the independent actions both of utilities and direct service industries.

The Council will continue to update its evaluation of the Administrator's need for, and the appropriate level of, an option inventory. The current surplus (including callback provisions on power sales outside the region) provide a de facto option inventory, but it is not sufficient to meet rapid load growth for more than a few years. As the current surplus shrinks, the Administrator will have to begin to option new resources. There is currently no consensus as to how big the option inventory should be, nor whose responsibility it is to pay for options. The Council will continue to work with all regional entities to try to resolve these questions.

Table 5-4
Resources Needed to Serve Current Bonneville Customers
and Investor-owned Utilities
(Medium-high Forecast in Average Megawatts)

RESOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
<u>Conservation Programs</u> (Cumulative annual energy savings)										
Single-family Residential MCS	1	3	5	7	9	12	14	17	19	21
Multifamily Residential MCS	0	0	1	1	1	2	2	2	2	3
Commercial MCS	0	0	1	2	3	5	8	11	14	17
Water Heat	0	0	0	0	0	0	1	4	8	12
Refrigerators	0	0	0	0	0	0	0	1	2	3
Freezers	0	0	0	0	0	0	0	0	1	1
New Manufactured Housing	0	1	2	3	4	6	7	9	10	11
System Efficiency Improvements	0	3	10	20	30	34	34	34	34	34
Irrigation	0	1	3	7	13	19	26	33	39	46
Industrial	0	3	12	27	48	72	96	120	144	169
Existing Commercial	0	12	44	88	135	182	229	275	322	360
Single-family Weatherization	0	0	5	19	39	59	79	99	120	135
Multifamily Weatherization	0	0	2	6	13	20	27	34	41	46
<u>New Generation Options</u> (Non-cumulative energy)										
Hydro Efficiency Improvements	110	0	0	0	0	0	0	0	0	0
New Hydro 1	62	10	10	5	0	0	0	0	0	0
Simple-cycle Combustion Turbine	0	230	230	230	0	0	0	0	0	0
New Hydro 2	76	7	11	11	0	0	0	0	0	0
Cogeneration	0	0	0	0	20	169	0	0	0	0
New Hydro 3	0	0	0	0	0	92	33	0	0	0
Licensed Coal Plants	0	0	0	0	452	452	0	0	0	0
Coal Plants	0	0	452	0	452	452	452	452	452	452

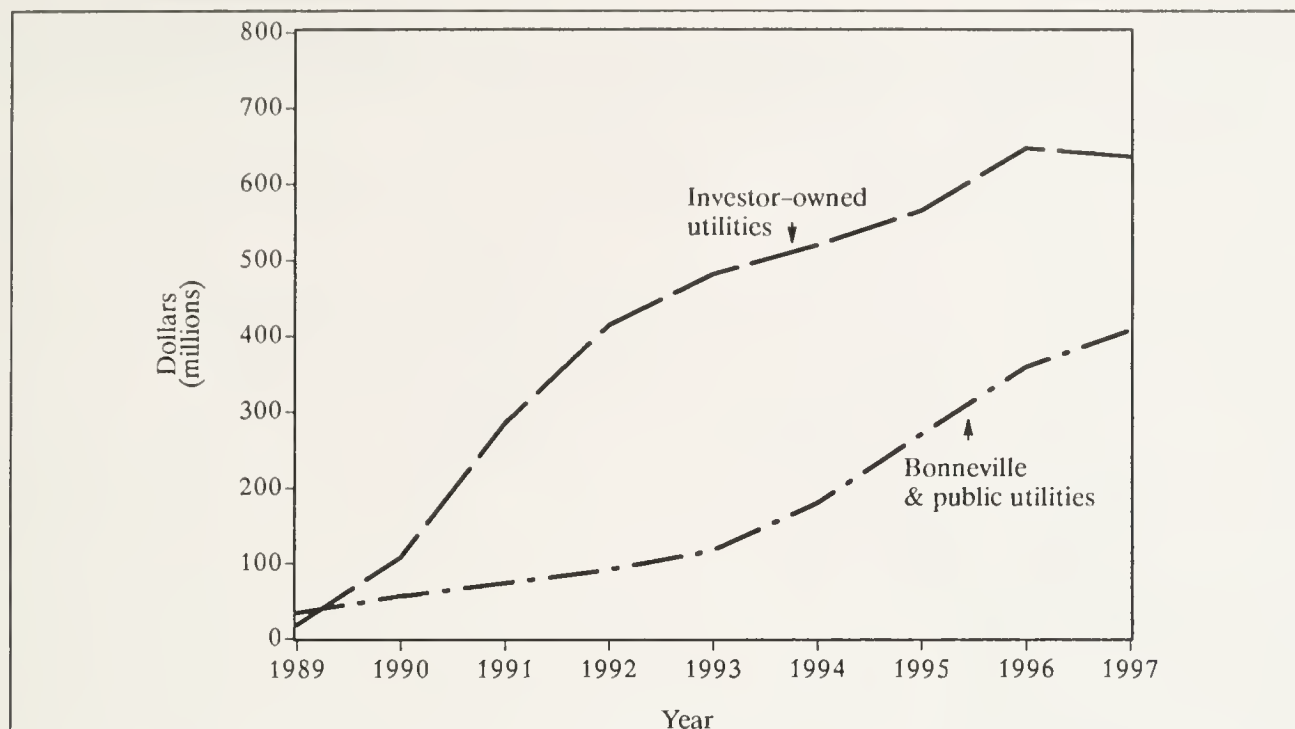


Figure 5-10
Projected Conservation Expenditures - Medium-high Scenario

Value of Resources Acquired During Surplus

Early development of resources that could be developed later depends on the resources' cost-effectiveness and their life-span. It may be cost-effective to develop some resources earlier than they are needed, but generally, only those resources that would otherwise be lost to the region should be acquired during the surplus. Further, early development of lost-opportunity resources should involve only environmentally acceptable ones.

This analysis evaluates the expected value of lost-opportunity resources based on the needs of the region as a whole. The region's utilities and public utility commissions need to evaluate the specific conditions of their ratepayers and decide on appropriate resource acquisition actions. The Council provides the following analysis as a general indication of the value of lost-opportunity resources

to the entire region. The Council will conduct additional analysis of the region's need for new resources and will help others assess individual circumstances that differ from the region as a whole.

The expected value of deferring all resources in the plan was used to evaluate the value of lost-opportunity resources acquired in 1990 and, alternatively, in 1995. Using a computer model (the Integrated System for Analysis of Acquisitions), a lost-opportunity resource was added in 1990. To bound the range of value over the next five years, a second case assumed the resource was added in 1995. These lost-opportunity resources were added to every load path, independent of the need for new resources. The result contributes additional surplus for the entire 20 years in low load paths. In high-load paths, the lost-opportunity resource displaces high-cost coal plants. In medium loads, the acquisition of a

lost-opportunity resource displaces primarily conservation.

The region is expected to benefit from acquiring lost-opportunity resources if they cost less than the expected cost of all resources they will displace. Figure 5-11 illustrates the resulting value of lost-opportunity resources acquired in 1990 or 1995. Since the value depends on the resource's lifetime, along with many other factors, Figure 5-11 shows the relationship of avoided cost to various lifetimes. This analysis shows that, for extremely short-lived resources of 10 years or less, the region benefits little from their early development, because the region is likely to be surplus during most of their life. For resources that are longer lived, the region in 1990 benefits from acquiring lost-opportunity resources that cost up to 3.5 cents per kilowatt-hour. Based on this analysis, during 1990 the region should not acquire lost-opportunity generating re-

sources unless they cost less than 3.5 cents per kilowatt-hour. Any resource that can be acquired for less than the value of nonfirm energy sales to California

should be secured as soon as possible. The maximum value for the same resource in 1995 would be about 4.0 cents per kilowatt-hour. These estimates will

need to be revised as regional conditions change and the region approaches the point of needing higher-cost resources.

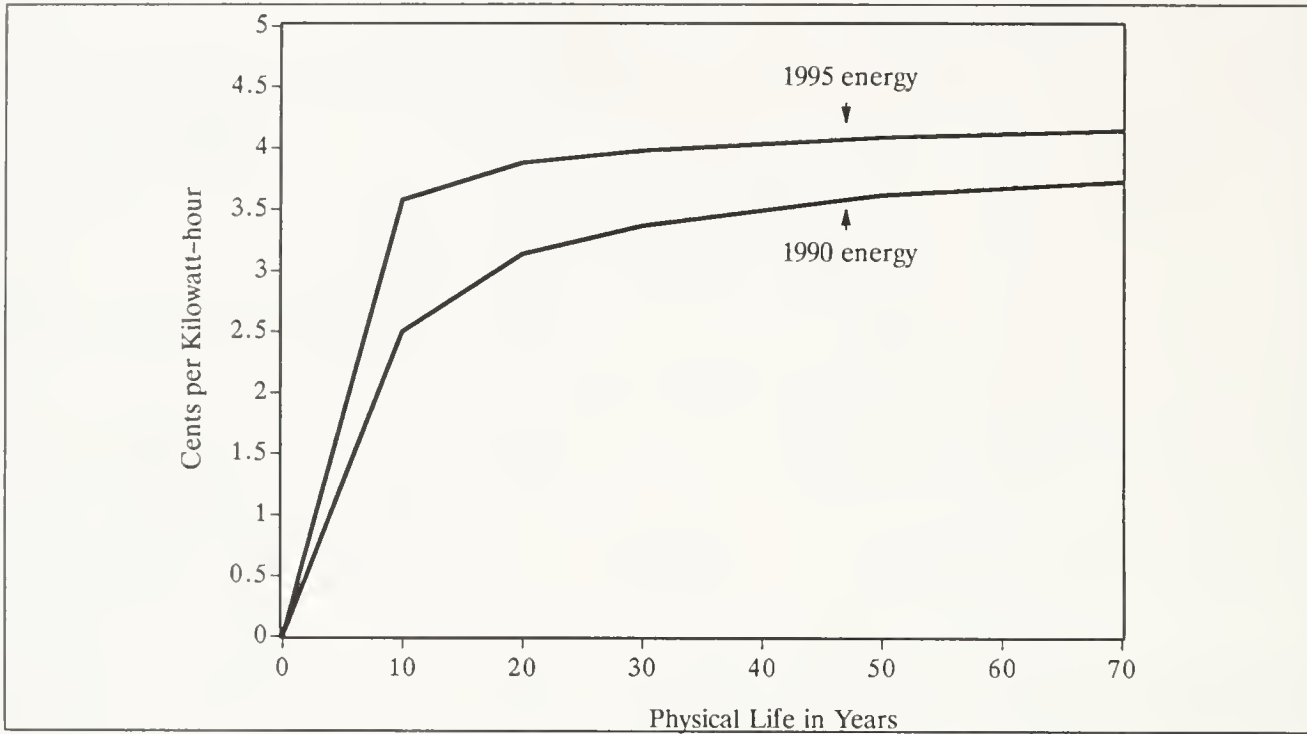


Figure 5-11
Value of Lost-Opportunity Generating Resources in the Portfolio

These estimates of the value of a lost-opportunity resource have been based on the addition of a single resource with a uniform contribution to the system across the year. Further, the resource's contribution does not vary as a function of the region's future load path. In order to use these estimates for the evaluation of conservation resources, the analysis must be modified to take into account both the seasonal load shape of conservation programs and the ability of some

conservation activities, such as the model conservation standards, to adjust their savings as a function of the load path the region experiences. In addition, for conservation programs, several other adjustments are necessary to correct for the emphasis in this analysis on the generation side of the region's power system. Because conservation programs affect savings at the load centers, these estimates of the value of a lost-opportunity resource need to be adjusted for trans-

mission system losses (7 percent) and costs (3 percent) before they are applied to evaluating conservation programs. Further, conservation programs are awarded a 10-percent cost advantage under the Northwest Power Act. Therefore, the values of lost-opportunity resources shown on Figure 5-11 need to be increased by 20 percent for evaluating a lost-opportunity conservation program.

